Transmission Use of System Charges for a System with Renewable Energy

Li, Jiangtao

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Transmission Use of System Charges for a System with Renewable Energy

Jiangtao Li

BEng

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Department of
Electronic and Electrical Engineering
University of Bath

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Contents

Abstract

Transmission charges are levied against generators and suppliers for their use of transmission networks. The majority of existing transmission charging methods were designed for a system dominated by conventional and controllable generation. The resultant transmission charges reflect network users' contribution to the system peak. The integration of renewable generation brings fundamental challenges in transmission planning and charging. Main criteria of transmission planning have changed from meeting system peak demand to the trade-offs between operational and investment costs. Transmission charging is required to effectively reflect these trade-offs.

This research work aims to develop novel transmission charging methods for low carbon power systems, reflecting the contribution to transmission investments from different generation technologies, different locations, and critically different times. It firstly identifies the key drivers and key conditions of transmission investments under the economic criteria. In the second step, the key drivers and conditions are reflected in the developing of T-LRIC method, ToU-LRIC method and ToU-ICRP method. Major innovations of the proposed methods include

- reflecting the trade-offs between operational and investments costs by employing investment time horizons to reflect the impacts of system operation on transmission investments (T-LRIC method and ToU-LRIC method).
- differentiating various generation technologies by firstly quantifying their impacts on the time horizons of network investments, then translating these impacts to transmission charges (T-LRIC method and ToU-LRIC method).
- providing time-specific transmission charges, in which Time-of-Use periods are identified by clustering time-series congestion costs or transmission charges, thus reflecting the typical conditions of system congestions and the required transmission investments (ToU-LRIC method and ToU-ICRP method).

The main benefits from introducing these innovations are i) to guide the short-run behaviours of network users, thus mitigating transmission congestions and promoting efficient utilization of existing networks; ii) to incentivize appropriate generation expansion, thus reducing or deferring costly future transmission investments.

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List of Figures

List of Tables

List of Abbreviations

ACER	Agency for the Cooperation of Energy Regulators
ALF	Annual Load Factor
BST	British Summer Time
CBA	Cost-Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CEGB	Central Electricity Generating Board
EHV	Extra High Voltage
ELEXON	Balancing and Settlement Code company
ELSI	Electricity Scenario Illustrator
ENTSO-E	European Network of Transmission System Operators for Electricity
FTRs	Financial Transmission Rights
ICRP	Investment Cost Related Pricing
LMP	Locational Marginal Pricing
LRIC	Long-Run Incremental Cost
LRMC	Long-Run Marginal Cost
MET Office	United Kingdom's national weather service
MITS	Main Interconnected Transmission System
NETS	National Electricity Transmission System
OCGT	Open-Cycle Gas Turbine
Ofgem	Office of Gas and Electricity Markets
PTDF	Power Transfer Distribution Factor

RIIO	Revenue = Incentives + Innovation + Outputs
ROC	Renewable Obligation Certificate
PRI-X	Retail Price Index – Efficiency Improvement
SQSS	Security and Quality of Supply Standard
SRIC	Short-Run Incremental Cost
SRMC	Short-Run Marginal Cost
tce	Tonne of coal equivalent
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
ToU	Time-of-Use
TSO	Transmission System Operator
TUoS	Transmission Use of System

List of Symbols

Δc	incremental capacity increase
$\Delta PF_{l,t}$	difference of power flows along branch *l* for time period *t*
ACC_l	annual congestion cost for network component *l*
AIC_l	annualized investment cost for network component *l*
B_l	transmission branch *l*
BCC_l	congestion cost allocated to branch *l*
C_{Gk}	capacity of generator *k*
CC_l	congestion cost allocated to branch *l*
$\underline{CC_{l,}}$	initial congestion cost allocated to branch *l*
$CC_{l,t}$	congestion cost for branch *l* allocated to time period *t*
$\underline{CC_{l,t,}}$	initial congestion cost for branch *l* allocated to time period *t*
CC_T	annual congestion cost with all branch capacity limits
$CC_{T,t}$	total congestion cost with all branch capacity limits at time period *t*
CC_{tx}/CC_{ty}	congestion cost for time periods t_x and t_y
$CC(i, k)$	congestion cost under *D(i)* and *W(i, k)*
CC_l^{in}	incremental annual congestion cost for branch *l*
$CC_{l,t}^{in}$	incremental congestion cost for branch *l* at time period *t*
CC_l^{L-l}	annual congestion cost with capacity limits except branch *l*
$CC_{l,t}^{L-l}$	congestion cost without capacity limit from branch *l* at time period *t*
CC_l^{mg}	marginal annual congestion cost for branch *l*
$CC_{l,t}^{mg}$	marginal congestion cost for branch *l* at time period *t*
d	fixed discount rate

d_{xy}	distance between congestion cost of time period t_x and t_y
D_i	demand connected at node *i*
$D_{i,T}$,	demand level for specific Time-of-Use period *T*
$D(i)$	demand value for demand level *i*
$DP(i)$	probability for demand level *i*
E	total embedded costs
EC	Expansion Constant
EC_T	Expansion Constant for Time-of-Use period *T*
EF_l	Expansion Factor for branch *l*
F_{li}	share of power flow of branch *l* from node *i*
G_i	generation capacity connected at node *i*
G_k	generator *k*
$GP_{k,t}$	output of generator *k* at time period *t*
IC	investment cost
$IC_{l,t}$	investment cost for branch *l* allocated to time period *t*
L_l	length of power line *l*
$LF_{Gk,T}$	load factor of generator *k* for Time-of-Use period *T*
$LRIC_{l,i}$	LRIC from network component *l* due to additional injection at node *i*
LSF	locational safety factor
m	total number of branches
$MW{*}km_i$	MW*km value for network user *i*
$MW{*}km_s$	MW*km value for electricity transaction *s*
n	total number of nodes
N_i	node *i*

NC_i	network charges for network user i
NC_s	network charges for electricity transaction s
NCC_i	congestion cost allocated to node i
$NCC_{i,t}$	congestion cost allocated to node i at time period t
P_i	magnitude of generation or demand for network user i at the time of system peak
P_{Gi}	generators' production costs
P_{peak}	total generation or demand at the time of system peak
$PAIC_l^{t_{inv}}$	present value of annualized investment cost for network component l at year t_{inv}
PD_i	demand peak at node i
PF_l	power flow along power line l
$PF_{l,s}$	power flow along power line l due to electricity transaction s
PF_{li}	power flow on branch l due to node i
$PIC_l^{t_{inv,t}}$	present value of investment cost for branch l at year $t_{inv,t}$ for time period t
$PTDF_{li}$	PTDF for branch l due to node i
r	demand growth rate
RC_l	rated capacity for network component l
$SCC_{i,T}$	nodal congestion costs for node i at all time periods contained in Time-of-Use period T
SF	scaling factor
SP_T	number of time periods contained in Time-of-Use period T
TC_{B6}	transmission capacity of B_6
t_{inv}	investment time horizon
t'_{inv}	new investment time horizon
$W(i, k)$	wind value for wind level (i, k)
$WP(i, k)$	probability of wind level (i, k)

Chapter 1

Introduction

THIS chapter briefly describes the background, challenges, motivation, objectives, and contributions of this thesis.

1.1 Background

1.1.1 Electricity Transmission

Transmission networks are the fundamental infrastructure for the bulk transfer of electricity, from points of generation to points of consumption. Transmission networks normally operate at very high voltages (275kV and 400kV in the UK, vary in other countries) to facilitate electricity transmission over long-distance [1]. Figure 1-1 briefly illustrates the electricity supply chain [2], which consists of electricity generation, transmission, distribution and consumption.

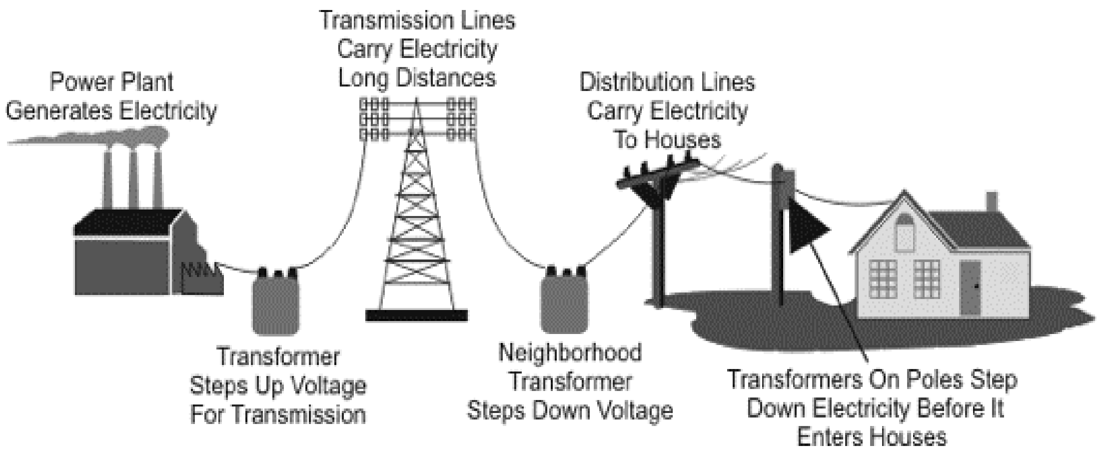

Figure 1-1 Brief Electricity Supply Chain

Over a very long period, electricity transmission was an integral part of the vertically integrated utilities, who were fully responsible for electricity generation, transmission, distribution and supply [3].

Since later 1980s, either to improve the efficiency of power systems or to attract investments for reducing governments' financial burden, deregulation and privatisation were introduced into the power industry, starting from Chile, then England & Wales, and onwards to many other countries around the world [4]. The deregulation and privatisation led to separated sectors along the electricity supply chain. Among them, electricity transmission was considered to be a monopoly, thus remained as a regulated business for the sake of public interests.

1.1.2 Transmission Planning

Before deregulation, monopoly utilities have direct control over electricity generation and transmission, thus clearly knowing the information such as generation efficiency and potential expansion, network reinforcement plans and related investment costs. On this basis, coordinated generation and transmission expansion planning was formulated to meet system peak demand, aiming to ensure a secure and reliable electricity supply with the minimum costs [5].

After the deregulation, the relationship between electricity generation and transmission becomes commercial. Transmission companies have no control over where and when generation plants should be built or decommissioned. They can only use transmission charges to influence the location, size and type of future generation plants [6]. As a supplement, indicative transmission expansion plans are published to inform network users the potential network investments [7].

1.1.3 Transmission Charging

During the period of monopoly utilities, the costs of electricity transmission were embedded in the total costs of providing the electricity supply, which were covered by the electricity bills from costumers. Therefore, there were no specific charges for electricity transmission.

After the restructure of the power industry, the necessities of pricing separated sectors emerge [8]. Generators and suppliers have to pay for their use of electricity networks. The costs that transmission companies have to recover fall into three main categories: i) connection charges: the asset cost of connecting network users to the shared transmission networks, ii) use of system charges: the investing and maintenance of the shared transmission networks, and iii) system balancing services charges to ensure the secure and reliable operation of transmission networks.

As electricity transmission is a regulated business, the revenue from this service is strictly controlled by the governments [9]. The allowed revenue not only ensures the full recovery of transmission costs, but also provides a reasonable rate of return for the sustainable developments of transmission networks.

Transmission Use of System (TUoS) charges, which are determined through economic charging methods, are charges against network users for their use of infrastructure network, allowing network companies to collect the allowed revenue for their investment and maintenance in transmission systems. Transmission charges undertake the significant roles of providing cost-reflective and economically efficient signals to the current and future network users, promoting effective utilization of existing networks and minimising future network expansion [10].

1.2 New Environment for Power Industry

1.2.1 Global Climate Change

The global economy is on the basis of large amounts of energy consumption. In 2012, the worldwide primary energy consumption reached its historical peak of 17.8 billion tce (tonne of coal equivalent), whereas higher numbers are forecasted for the coming years [11]. Particularly, fossil fuels take 90% share in the primary energy consumption in 2012, in which coal occupies 29.9%, gas takes up 23.9% and oil accounts for 33.1% [12]. The burning of fossil fuels cause the emission of greenhouse gases (CO_2, N_2O, CH_4 and *etc.*), which exacerbate the global climate change and causes serious disasters including species extinction, frequent extreme weather and rising sea-levels.

To avoid these severe disasters, effective measures must be taken. In 1997, 39 developed countries and the European Union (EU) signed the ‘Kyoto Protocol’, in which they committed to reducing their greenhouse gas emission [13]. Recently, EU set its ambitious quantifiable ‘20-20-20’ targets for 2020, which include a 20% reduction of EU greenhouse emission from the 1990 levels [14]. Particularly for the United Kingdom (UK), the government commits to reducing the greenhouse gas emission by at least 80% by 2050 relative to the 1990 level [15].

1.2.2 Renewable Generation Development

Particularly for 2012, 41.2% of the world’s total CO_2 emission (12.48 billion ton) comes from electricity generation [16]. Therefore, the aforementioned ambitious emission reduction targets require massive conventional generation to be replaced by zero-emission renewable generation.

The past decade witnessed an increasing share of renewables in the worldwide generation mix. In 2000, renewables (excluding hydro) only occupied 0.9% of the total generation mix. In contrast, this number increased to 6.8% in 2012, with a total installed renewable generation capacity of 376GW (total generation capacity: 5500GW) [11]. EU's ambitious '20-20-20' targets include a 20% share of EU energy consumption from renewable resources in 2020 [14]. In the UK, the overall target is that 15% of energy consumption come from renewable sources by 2020 [17]. Particularly for the power industry, more than 30% of electricity is projected to be from renewables in 2020. Figure 1-2 shows the electricity generated from renewables in the UK from 2003 to 2013 [18]. It is remarkable that during the period from July 2012 to June 2013, electricity generated from renewable sources contributes to 13.1% of the total electricity generated.

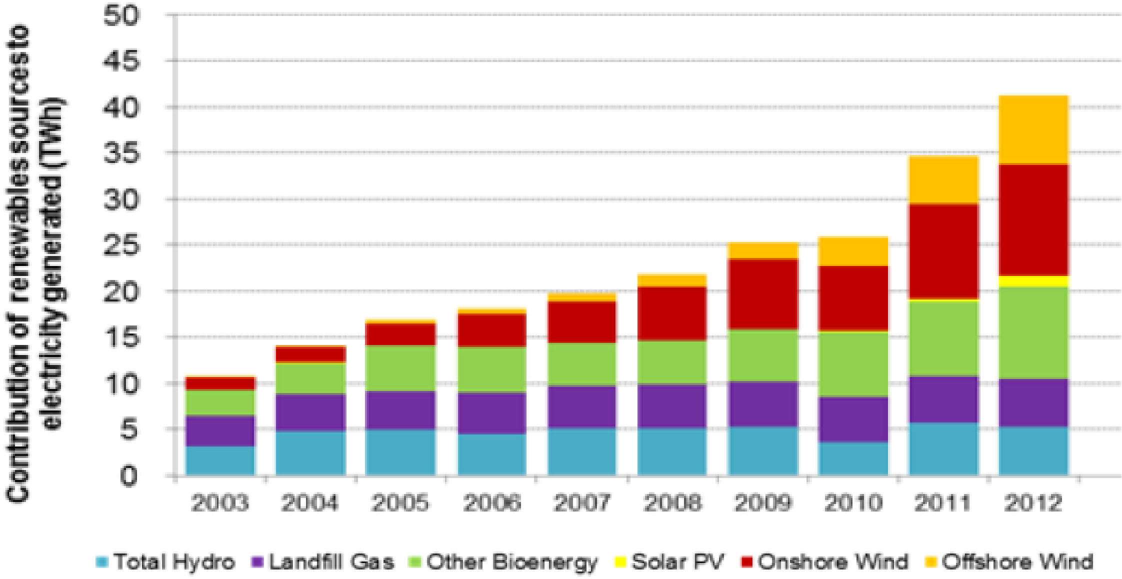

Figure 1-2 Electricity Generated from Renewables in the UK between 2003 to 2013

1.3 Challenges for Electricity Transmission

Transmission networks are the foundation of integrating renewable generation into power systems. However, the integration of renewable generation causes serious challenges to electricity transmission, including:

1. **Causing more frequent transmission congestions in system operation**

While conventional generation that are controllable and available in most of the time, the output of renewable generators are subject to the availability of renewable resources. Therefore, the sudden high output from renewable generation would cause more frequent transmission congestions, not limited to high demand periods but anytime when renewable resources are abundant [19].

2. **Requiring more transmission capacities but under-utilized**

The large deployment of renewable generation requires more transmission infrastructure to be built, but the capacity of these facilities are under-utilized due to the intermittence of renewables. In fact, it is not economical to build excess transmission capacities for renewable generation because of the high investment costs [20]. Transmission investments need to be justified based on the trade-offs between operational costs due to generation re-dispatch and investment costs from network upgrades.

3. **Making existing transmission charging methods inefficient for low carbon generation**

Traditional transmission charging methods were designed for power systems dominated by conventional generation, thus the resultant transmission charges only reflect network users' contribution to network investments dictated by the system peak. These charges are inefficient for renewable generation, as they are not reliable for meeting system peak due to their intermittent feature [21]. Therefore, fundamental changes in transmission charging are required for a low carbon future.

1.4 Research Motivation

Under the low carbon transition of the power industry, the Investment Cost Related Pricing (ICRP) method employed by the UK to derive transmission charges has the following drawbacks.

1. **Unable to recognise the trade-offs between operational and investments costs in transmission planning**

Existing ICRP method solely employs a single scenario of system peak to derive transmission charges, basing on the assumption that network users make their maximum utilization of transmission networks during the period of system peak. However, due to the integration of renewable generation, transmission network investments become based on the trade-offs between operational and investment costs. Urgent improvements are required to reflect these trade-offs, thus reflecting network users' contributions to transmission investments for the low carbon transition.

2. Unable to distinguish conventional and renewable generation

Existing ICRP method scales generation capacity uniformly down to demand level irrespective of the generation technologies. Consequently, ICRP method cannot distinguish the significant difference of availability between conventional and renewable generation, and reflect their different contributions to network investments. To provide cost-reflective transmission charges, differentiating generation technologies is urgently required.

3. Unable to reflect the transmission investments required at different times

Existing ICRP method provides fixed annual transmission charges, assuming that network users only contribute to the transmission investments required for system peak. However, due to the intermittent feature of renewable generation, the level of required transmission investments become triggered by system operation through the year, especially when substantial renewable generators are deployed. It is urgent to reflect the required transmission investments throughout the year, thus charging network users based on their varying contributions at different times.

1.5 Research Objectives

This research work aims to develop novel transmission charging methods for the undergoing low carbon transition in the power industry. The main objectives of this research work are:

1. **Recognised the trade-offs between operational and investment costs in transmission investments decision making**

As the existing ICRP method is a deterministic approach based on pre-known inputs, the trade-offs between operational and investment costs are difficult to be recognised. The recognition of these trade-offs requires to introduce complex algorithm of comparison into transmission charging, which should be achieved in the proposed transmission charging methods in this thesis.

2. **Distinguish the conventional and renewable generation in triggering transmission investments**

The significant difference between conventional and renewable generation are their production costs and availabilities, which in turn determine their different requirements on transmission investments. However, only generation capacity but not production costs and availabilities are reflected in the existing ICPR method. How to reflect production costs and availabilities need to be addressed in the proposed transmission charging methods in this thesis.

3. **Reflecting the different levels of transmission investments required at different time around the year**

As the existing ICRP method only employs a single scenario, it is insufficient to reflect the different levels of transmission investments required at different times around the year. The proposed transmission charging methods in this thesis need to develop representative scenarios to reflect network users' varying behaviours during different times, thus different contributions to transmission investments.

1.6 Research Contributions

The major contributions of this research work are summarised as follows:

1. This research work creatively acknowledges the trade-offs between operational and investment costs in transmission investments under the economic criteria. By comparing the congestion cost and investment costs for a future time, the time horizons of transmission investments are employed to reflect these trade-offs, and used as the measure to derive transmission charges.

2. This research work successfully innovates the traditional transmission charging method to differentiate generation technologies, by quantifying the impacts of different generation technologies on the time horizons of network investments due to

additional unit capacity. By providing cost-reflective and generation technology-specific transmission charges, future generation expansion will be attracted to appropriate locations, thus in turn reducing the otherwise required transmission investments.

3. This research work innovatively changes the traditional annual transmission charges to time-specific charges. Time-of-Use periods are identified by clustering time-series transmission charges, thus reflecting the different levels of system congestions and different levels of required transmission investments. Time-specific charges can offer network users economic incentivizes to adjust their short-run network utilization behaviours, thus promoting the efficient utilization of existing networks.

4. This research work demonstrates the benefits from introducing the above innovations over the existing Investment Cost Related Pricing (ICRP) transmission charging method used in practice, particularly in differentiating generation technologies and providing time-specific charges.

1.7 Thesis Outline

The layout of this thesis is given as follows:

Chapter 2 briefly explains the roles and principles of transmission charging. Then, it presents a comprehensive overview of transmission charging methods for high carbon power systems and the international experience. Afterwards, it introduces the changes in transmission planning for low carbon power systems and the recent developments in transmission charging. Finally, it summarizes the essential features of transmission charging for a low carbon future.

Chapter 3 explores the key drivers of transmission investments under low carbon environment, choosing from various factors from generation, transmission, and demand sectors. The analysis is based on a two-bus power system to explain the philosophies. Afterwards, a simple representation of the Great Britain power system is employed to identify the key conditions when and where transmission investments are required.

Chapter 4 proposes a novel transmission charging method that can provide generation technology-specific charges. The proposed method is demonstrated on a modified IEEE

14-bus power system. The resultant charges for different generation technologies are compared with those under the existing ICRP method.

Chapter 5 improves the proposed method in Chapter 4 to offer time-specific charges. The proposed method is demonstrated on the modified IEEE 14-bus power system. The benefits of time-specific charges are analysed. Moreover, shortcomings about the proposed method are summarized.

Chapter 6 improves the existing ICRP method in being able to differentiate generation technologies and provide time-specific charges. It aims to strike the right balance between simplicity and accuracy. The proposed method is demonstrated on the modified IEEE 14-bus power system. The advantages and disadvantages of the proposed method are summarized. A comprehensive comparison between the proposed TUoS charging methods in this thesis are given.

Chapter 7 summarizes the key findings and major contributions from this research work, and presents the potential future works that can further improve the research in considering different demand profiles, reliability driven transmission investments and revenue recognition.

Chapter 2

An Overview of Transmission Charging Methods

THIS chapter gives a review on transmission charging methodologies for traditional high carbon power systems and introduces the recent developments for a low carbon future.

2.1 Roles and Principles of Transmission Charging

Either to improve the efficiency of power systems or to ease the financial burden for the governments, deregulation and privatization were introduced into the power industry since late 1980s [4]. Consequently, the power industry was divided into separated sectors, necessitating the developing of electricity network charging methodologies.

This section explains the roles of transmission charging and presents the principles in designing transmission charging methods.

2.1.1 Roles of Transmission Charging

Transmission charges are basically to recover the costs incurred in providing transmission services [10, 22]. This section gives some brief introductions about transmission costs (section 2.1.1.1), transmission revenue (section 2.1.1.2) and transmission charges (section 2.1.1.3).

2.1.1.1. Transmission Costs

The costs in providing transmission services consist of [23-25]:

- Investment costs of transmission equipment and assets used to facilitate electricity transmission, as well as their depreciation and maintenance.

- Operational costs, such as transmission losses due to the impedances of power lines and other equipment, congestion costs due to congestion management.

- Management costs such as staff remuneration, office and travel expenses, and so on.

2.1.1.2. Transmission Revenue

Since electricity transmission is a regulated business, the governments strictly regulate the revenue from providing this service [9]. The regulation can guarantee the sustainable development of transmission networks, meanwhile prevent super profits from this monopoly business.

There are two categories of revenue regulation methods:

- Rate of return based regulation

This category includes the "cost-plus-profit" method and "cost of service" method. In these methods, the governments (such as United States, Japan) periodically audit the transmission costs that are eligible to be covered through transmission charges, and set the profit as a proportion of the transmission costs [26, 27]. Since these methods determine allowed revenue based on transmission costs, they provide network companies with wrong incentivizes to over-invest transmission networks.

- Performance based regulation

This category includes the "price cap" method, "revenue cap" method and "yardstick competition" method. In these methods, the governments (such as the United Kingdom, Australia and Norway) no longer directly set the allowed revenue through the rate of return. Instead, revenue is adjusted by expected inflation rate and "efficiency improvement" rate set by the governments [26, 27]. For example, "PRI-X" regime employed in the UK includes "PRI" (Retail Pricing Index) for expected inflation and "X" for the required efficiency improvement [28]. These methods require high capability of governmental regulation, but efficiently encourage network companies to improve efficiency.

A recent development of revenue regulation in the UK is the RIIO model, in which "Revenue = Incentivizes + Innovation + Outputs" [29]. RIIO model is on the basis of previous PRI-X regime but better meets the investment innovation challenges [28]. It does this by placing more emphasis on i) invest efficiently to ensure continued safe and reliable services and ii) innovate to reduce network costs for current and future consumers.

2.1.1.3. Transmission Charges

Transmission charges are to collect the allowed revenue of transmission network companies, which is very different from the pricing of electrical energy, neither wholesale nor retail. Normally, there are three kinds of transmission charges [30]:

- Connection charges

Connection charges are for network user's physical connection to transmission networks, recovering the costs in the physical connection assets between network users and the nearest network connection points, which are solely utilized by a particular network user.

- Use of system charges

Use of system charges are for network users' utilization of the shared transmission network infrastructure. The majority of existing transmission charging methods are designed for transmission use of system charges.

- Transmission operational charges

Transmission operational charges are for the costs of transmission services in congestion management and losses, which are required to facilitate electricity trading and to ensure secure system operation.

2.1.2 Principles of Transmission Charging

In competitive environments, transmission charges also bear the duty to offer forward-looking, economic signals to network users for the efficient utilization of existing networks and the appropriate development of future networks. Generally, the principles in designing transmission charging methods are [31-34]:

1. **Economic efficiency**

Economic efficiency refers to that transmission charges should be efficient in guiding the behaviours of both existing and potential network users' behaviours, for the effective utilization of existing networks and efficient development of future networks.

2. **Cost reflectivity**

Cost reflectivity refers to that network users should be responsible for the transmission costs they incur, and this causality is reflected in transmission charging methods.

3. **Transparency**

Transparency refers to that the procedure of deriving transmission charges should be simple enough to be understood by all network users and repeatable for their own calculation. Moreover, the calculation inputs should be publicly available information.

4. **Predictability**

Predictability refers to that transmission charges should be stable and predictable so as to minimize the uncertainties in the decision making of existing generation closure and future generation expansion.

5. **Promoting competition**

Promoting competition refers to that transmission charging should ensure the open and fair access to transmission networks for all network users, without placing obstacles for free competition in generation and retailing sectors.

6. **Accommodating Policies**

Accommodating policies refers to that the influences of transmission charges should be aligned with government's energy policies, such as promoting the utilization of renewable resources and reducing greenhouse gas emission.

One should bear in mind that it is not practical to achieve all the aforementioned principles in a transmission network charging method. For example, a method that fulfils the principle of cost reflectivity would always be complex, which is unavoidably conflict with the principle of transparency. Therefore, trade-offs between these principles must be taken in designing transmission charging methods.

2.2 Status Quo of Transmission Charging

In this section, existing electricity network charging methods for traditional high carbon power systems are summarized, the international experience on transmission charging are given.

2.2.1 Classification of Existing Charging Methods

In the past few decades, numerous electricity network charging methods have been developed and applied into practice. Based on their difference in translating network costs into network charges, the existing charging methods are grouped into three categories [23, 35].

- Embedded Cost methods
- Marginal or Incremental methods

- Composite Embedded and Marginal/Incremental methods

2.2.1.1. Embedded Cost Methods

In embedded cost methods, all existing network costs and the new costs for network expansion (so called embedded costs), regardless of their causes, are firstly summed up into a single number, then allocated to network users according to different definitions of the "extent of use" of networks [23, 26, 31, 35-39]. These methods define and evaluate the "extent of use" differently.

1. Postage Stamp method [23, 35]

In Postage Stamp method, embedded costs are allocated to network users based on the magnitude of generation or demand at the time of system peak, regardless of their connection locations.

$$NC_i = E \times \frac{P_i}{P_{peak}} \qquad \text{(Eq. 2-1)}$$

where NC_i is the network charges for network user i, E is the total embedded costs, P_i is the magnitude of generation or demand for network user i at the time of system peak, and P_{peak} is the total generation or demand at the time of system peak.

The main justification of Postage Stamp method is its simplicity. However, this method ignores the actual operation of power system. It cannot provide efficient locational signals for network users to reflect their impacts on system operation or expansion. It cannot provide signals to indicate where the networks are highly utilized thus connection to these locations should be avoided, as the upgrade costs are shared among all networks users without considering their connecting locations.

2. Contract path method [23]

In contract path method, a specific path between the generation point and consumption point, which is called the "contact path", is selected without performing power flow analysis. Then a partial or all embedded costs for the facilities along this "contact path" are allocated to the network users at the generation and consumption points.

Contract path method is effective in small power systems, as if network upgrades were required, the resultant costs are simply added to the embedded costs. However, this method also ignores the actual system operation. It assumes that power flow is confined along the selected "contact path". In fact, the actual power flow may be along power lines outside the selected path and the embedded costs for these power lines cannot be fully allocated. Although this method considers more of locations than the Postage Stamp method, it is still not effective in reflecting the actual costs incurred by network users.

3. Physical distance based MW*km method [26]

Physical distance based MW*km method allocates embedded costs among electricity transactions based on the magnitude of transacted power and the physical distance between the points of generation and consumption.

$$NC_s = E \times \frac{MW*km_s}{\sum MW*km_s} \quad \text{(Eq. 2-2)}$$

where NC_s is the network charges for electricity transaction s, E is the total embedded costs, $MW*km_s$ is the MW*km value for electricity transaction s.

Physical distance based MW*km method also neglects the actual operation of power systems, as the physical distance does not indicate the exact costs to serve electricity transaction. This method also provides inefficient signals to network users.

4. Power flow based MW*km method [26, 35]

Power flow based MW*km method allocates embedded costs through power flow analysis which simulates the actual operation of power system.

The total MW*km of electricity transaction s, $MW*km_s$, is calculated as the summation of MW*km along individual power lines.

$$MW * km_s = \sum (L_l \times PF_{l,s}) \quad \text{(Eq. 2-3)}$$

where L_l is the length of power line l, $PF_{l,s}$ is the power flow along power line l due to electricity transaction s.

The embedded costs then are allocated to various electricity transactions.

$$NC_s = E \times \frac{MW*km_s}{\sum MW*km_s} \quad \text{(Eq. 2-4)}$$

where NC_s is the network charges for electricity transaction s, E is the total embedded costs, $MW*km_s$ is the MW*km value for electricity transaction s.

Power flow based MW*km method can recognise the magnitude, path and distance of electricity transactions, therefore it is effective in reflecting the 'extent of use' of networks. However, it can only analyse the impacts of individual transactions in existing networks but not their influences on the future network upgrades.

There are other embedded cost methods [23], such as Modulus method, Zero Counter flow method, and Dominant Flow method, which are however not introduced in this thesis.

In summary, the obvious defects of embedded cost methods are that they cannot provide forward-looking signals to discriminate between network users or electricity transactions who cause additional network reinforcements and who reduce or delay otherwise required network upgrades.

2.2.1.2. Marginal or Incremental Cost Methods

In order to overcome the drawbacks of embedded cost methods, marginal or incremental cost methods are introduced [31, 32, 40-43]. These methods provide marginal or incremental changes in transmission costs as the economic signals to network users.

Two issues should be explained before introducing marginal or incremental cost methods [41].

- The first issue is what costs are included, i.e. short-run or long-run. Short-run and long-run costs differ in the parts of network costs that are taken into account. Short-run methods evaluate the additional operational costs due to new network users. By contrast, long-run methods evaluate both the additional operational and investment costs necessary to accommodate new network users.
- The second issue is whether costs are evaluated marginally or incrementally. Incremental cost is determined by comparing the network costs with and without the entire network user or electricity transaction. Marginal cost is determined by multiplying the network cost for additional unit of electricity generation or demand with the size of network user or electricity transaction. Normally, there is large difference between incremental cost and marginal cost.

Marginal or incremental cost methods include

1. **Short-Run Incremental Cost (SRIC) method [41]**

SRIC method evaluates and assigns the additional operational costs for a new electricity transaction or network user. The operational cost can be estimated via an optimal power flow model that considers all operational constraints in transmission networks (capacity limits, voltage limits and *etc.*) and electricity generation (rated capacity, ramping rate, minimum start-up and shut-down time). It should be noted that SRIC may be negative, reflecting the fact that new network users may help to reduce the total operational costs.

SRIC method only considers operational cost, which becomes the revenue for network companies. Therefore, this method would discourage network expansion. This is because if the networks were upgraded, SRIC would decrease dramatically thus reducing network companies' revenue.

2. **Long-Run Incremental Cost (LRIC) method [41]**

LRIC method evaluates all long-run costs (operational and reinforcement costs). Reinforcement cost can be evaluated based on the changes in long-term network expansion plan. Similar to operational costs, reinforcement cost may be negative, reflecting the fact that new network users may help to defer or reduce planned network reinforcements.

Although the concept of reinforcement cost is very straightforward, its evaluation is quite difficult as this requires to execute a network expansion mode that targets to minimise costs. Furthermore, the allocation of reinforcement costs between different network users are very complex.

3. **Short-Run Marginal Cost (SRMC) method [41]**

In SRMC method, the marginal operational cost per MW is calculated first. Then, it is multiplied by the magnitude of the new network user or electricity transaction to get the short-run marginal cost.

Due to the non-linear relationship between additional unit injection (the slope rate of the operational cost curve at the point of marginal increase) and the entire electricity transaction (the slope rate multiplied by the magnitude of the electricity transaction), the

SRMC are higher than the actual operational cost of accommodating the new network user or electricity transaction. This extra "profit" would be accumulated by network companies to fund future network expansion.

4. Long-Run Marginal Cost (LRMC) method [41, 42]

In LRMC method, the operational marginal cost is calculated via a similar way as SRMC. Over a "long" time horizon of several years, all network expansions are identified first. LRMC method then evaluates the changes in network expansion due to an additional unit injection. Long-run marginal reinforcement cost is obtained by multiplying the changes with the magnitude of new network user or electricity transaction.

In summary, although marginal and incremental methods are efficient in providing forward-looking signals, they have the following drawbacks [40-42]:

- Marginal cost methods make an inaccurate assumption that the relationship between additional unit injection and the entire electricity transaction or network user is linear.
- Long-run methods determine network expansion plan for a future time based on projected generation and demand pattern. Therefore, these methods only passively react to forecasted future generation and demand, rather than proactively affect their siting and sizing. Moreover, future generation/demand predictions are far from certain, which may result in wholly inappropriate charges.
- Even worse, purely economic signals from marginal or incremental methods cannot guarantee the full recovery of investment costs. In practice, marginal/incremental methods are usually combined with embedded cost methods to allocate both existing and new network costs among both existing and new network users.

2.2.1.3. Composite Embedded and Marginal/Incremental Cost Methods

Composite methods are actually a combination of embedded cost methods and marginal/incremental cost methods [44]. They look for a reasonable balance between guaranteeing the full recovery of the allowed revenue and providing economic incentivizes, for both existing and future network users.

In practice, network charging methods employed by different countries are rarely based on a single method, but combine different methods to achieve a high level of cost-reflectivity and economic efficiency. International experience on transmission network charging methods are given in the next section.

2.2.2 International Experience on Transmission Charging

One cannot straightforwardly compare transmission charging methods in different countries, as they are not in a unified framework but differ largely due to different industry structures, market designs and regulation rules.

Transmission charges in different countries may differ in the following aspects [45]:

- the payer of transmission charges---demand solely, generation solely, or both generation and demand;
- the measure of transmission charges---energy based (per MWh) or capacity based (per MW);
- the number of types of transmission charges---separated charges for operational costs (losses, congestion management and *etc.*) and investment costs, or a single charge for both costs;
- the impact of locations on transmission charges---non-locational, nodal or zonal;
- the impact of utilization time on transmission charges---seasonal and/or time-of-day;

This thesis does not intend to explain the very details of transmission charging methods in every country, but only to mention the noteworthy features of **Transmission Use of System (TUoS) charges** in different countries.

Table 2-1 introduces the international experience on transmission charging methods [22-24, 30-32, 40, 46-48].

Table 2-1 International Experience of Transmission Charging Methods

Country	*Transmission Charging Methods*
Argentina [47]	1. nodal pricing based on bids; 2. 100% from generation.

Brazil [31, 40]	1. modified Investment Cost Related Pricing (ICRP) method, reflecting the network topology in Brazil; 2. 15% based on locational charges, 85% from average distribution.
Chile [31, 47]	1. nodal pricing based on costs of investment, operation and losses; 2. consider distance and power magnitude; 3. 90% based on distribution factor, 10% based on locational charges; 4. 100% from generation.
China [46]	1. vertical monopoly utilities for transmission, distribution and retailing; 2. transmission costs covered by the difference in electricity generation and retail prices (both set by the government); 3. ongoing reform targets to differ for voltages; 4. fixed transmission charges for special transmission projects.
Finland [31]	1. time-specific, including normal charges and winter peak charges; 2. 17% from generation, 83% from demand.
France [31]	1. transmission charges for two voltage levels, 10kV-130kV and 130kV-350kV; 2. non-locational charges; 3. discounted by Utilization Hours (Energy transferred/Applied Transmission Capacity); 4. 2% from generation, 98% from demand.
Germany [48]	1. specific for voltage levels, using a cascading principle; 2. non-locational charges; 3. 100% from demand.
Ireland [30, 48]	1. cover the costs in investment and system services (loss covered in energy market); 2. only locational for generation; 3. 20% from generation, 80% from demand.
Japan [31]	1. 10 regional vertical monopoly utilities for generation, transmission, distribution, and retailing; 2. transmission charges are added to electricity tariff per kWh; 3. cross-regional transmission charges.
New Zealand [47]	1. fixed transmission charges for connection, use of system; 2. transmission expansion are judged by the prices difference in electricity spot prices (nodal marginal costs).

Norway [30, 47]	1. zonal transmission charges (3 zones); 2. ignore the distance travelled; 3. transmission charges differ in utilization time, via losses; 4. 35% from generation, 65% from demand;
Spain [48]	1. determined based on Postage Stamp method, regardless of connection points and voltage levels; 2. adjusted annually; 3. 100% from demand.
Sweden [48]	1. annual fixed transmission charges; 2. locational charges based on connection points; 3. 33% from generation, 67% from demand.
United Kingdom [22]	1. Investment Cost Related Pricing (ICRP) method; 2. locational charges for generation and demand; 3. 27% from generation, 73% from demand.

For a clear understanding of the work presented later in this thesis, detailed introductions for the United States and the United Kingdom are given.

2.2.2.1. United States

The reforms in the USA power industry are very different from that in other countries such as the UK, leading to a different development of competitive electricity markets [47]. The power systems in different states are not forced to be deregulated by the federal law. Therefore, the structure of power industry in different states are largely varying even some still remain as vertical monopoly [2]. In the deregulated states, electricity trading arrangements are mainly based on central dispatch rather than via bilateral contracts in other countries such as the UK.

When talking about the power industry in the United States, a widely discussed issue is Locational Marginal Pricing (LMP) method, which is used in competitive electricity markets in California, New England, New York, PJM and Texas [30]. It should be emphasized that, LMP method’s efficient applications in managing transmission congestion and providing locational electricity prices are mainly for operational costs (both transmission and generation), but not for covering network companies’ investment costs [49].

In wholesale electricity markets, the electricity prices from LMP method reflect the locational values of electrical energy, which depend not only on the generators' production costs but also on the transmission network characteristics [49, 50]. In LMP method, generator/demands are paid /charged for their generation/consumption on the basis of their nodal prices. These short-run nodal prices can

- present transparently the true costs of power system in serving demands at different locations and times;
- price transmission service (mainly loss and congestion) and energy consistently in wholesale electricity market;
- provide economic incentivizes for generation expansion, transmission upgrades and demand growth in the best locations.

Different nodal prices cause a serious problem of Merchandising Surplus, which comes from that the payment collected from demand is larger than the payment to generation [49]. Financial Transmission Rights (FTRs) which is the right to access transmission capacity and acquired through auctions, are employed to solve Merchandising Surplus problem. However, this is out of the scope of this thesis (detailed introduction is available in [8]).

As mentioned above, LMP method is not to recover network investment costs. In PJM electricity market, a so-called "DFAX method" is employed to cover the transmission investment costs (both connection and the shared networks). It firstly examines the violations in system reliability due to new network users for a chosen snapshot of system operation (normally system peak). Afterwards, it quantifies the required investment costs to maintain reliability level and assigns the costs to the new network users [51]. In some literature [30, 45], this is called 'deep' connection charges, which are believed to be economically efficient.

2.2.2.2. United Kingdom

In the United Kingdom, there are three kinds of charges against transmission network users [52], as shown in Table 2-2. This thesis only introduces the Transmission Network Use of System (TNUoS) charges in details. Connection charges are specific for individual network users who benefit from the assets that connect them to the shared transmission networks. Balancing Services Use of System charges are system charges for the reliable and secure operation of the whole system.

Transmission Network Use of System charges consist of two elements:

1. A locational varying element

The derivation of locational varying element employs a DC (Direct Current) load-flow Investment Cost Related Pricing (ICRP) transport model, which was employed in the UK since 1993 [53, 54]. (Detailed procedure is given in Appendix A-1.)

Table 2-2 Charges againse Transmisison Network Users in the United Kingdom

Charges	*Feature*
Connection charge	1. to cover the costs of the transmission assets for particular network users; 2. specific for individual network users;
Transmission Network Use of System charge	1. to cover the transmission costs of investment and maintenance for Main Interconnected Transmission System (MITS); 2. employ Investment Cost Related Pricing method;
Balancing Services Use of System charges	1. to cover the transmission costs of operational loss, congestion management; 2. costs are equally distributed among generation and demand;

ICRP method employs the principle of power flow based MW*km method to calculate the cost of providing transmission capacity to cater for an additional generation or demand at each node. This model is based on a single scenario of system peak in which generation capacities are uniformly scaled down to match demand. And the measure in ICRP method is the distance (MW*km) that electricity has to travel from the points of generation to the points of consumption at the time of system peak.

In order to reflect the difference in transmission costs at different voltages and cable routes, circuits' expansion factors are employed. The resultant marginal difference in MW*km due to an additional injection are converted into transmission charges (initial locational varying elements) by the application of Expansion Constant (EC), Expansion Factors (EF) and Locational Safety Factor (LSF).

- **Expansion Constant** represents the annualized cost of transmission infrastructure investments required for transporting 1MW over 1km [53]. The magnitude of this annualized cost is based on the predicted future values for 400 kV overhead line.

- **Expansion Factors** represent the cost of other types of overhead lines and cables relative to the cost of 400 kV overhead line [53].

- **Locational Safety Factor** represents the cost required to provide reliable transmission service during outage and contingency on a locational basis [53]. Currently, an indicative value of 1.8 is employed, which is an approximate average value for the whole networks to represent the varying costs required at different locations.

After the initial locational elements are calculated, a correction factor is applied to guarantee the correct split (27:73) between revenue collected from generation and demand.

2. A non-locational element

After the split is corrected, a flat residual non-locational element is added to guarantee the full recovery of allowed revenue, which is set by the industry regulator---Ofgem (Office of Gas and Electricity Markets).

Currently, generators are charged based on their Transmission Entry Capacity (TEC), which is the maximum amount of electricity a generator is allowed to export to transmission networks.

In summary, ICRP method can ensure the full recovery of allowed revenue. At the same time, it provides economic signals for the siting and sizing of future generation and demand. However, it has the following drawbacks:

- It assumes that existing networks are fully utilized and any additional power flow as a result of nodal injection/withdraw will immediately trigger network reinforcements. This assumption fails to recognise the influence of congestion management in deferring network investments [55].

- It assumes that a circuit is infinitely divisible so that an additional 1MW power flow can be met by the addition of a circuit with 1MW capacity. This assumption fails to recognize the rated capacities of transmission branches.
- It scales down generation capacity uniformly regardless of the technologies employed and charges network users solely based on a single scenario of system peak. In fact, different generators with various technologies use transmission network differently [56]. It fails to distinguish conventional and renewable generation, causing significant cross-subsidies among generators that employ different technologies.

2.3 Changes in Transmission Network Planning

2.3.1 Traditional Transmission Planning

For a very long period, power systems are dominated by conventional generators, most of which are controllable and available on request most of the time. The criteria in transmission network planning have not changed too much, even when the power industry was deregulated and privatised from vertical monopoly utilities [57].

In the case of the vertical monopoly utilities, transmission network planning was reliability driven, i.e. targeting to minimize the investment costs in new transmission infrastructure to provide reliable service for a future demand and generation configuration [58]. During this period, transmission network planning was always combined with generation expansion planning, aiming to achieve the maximum of social welfare [5]. As the vertical monopoly utilities had complete control over generators, the traditional centralized planning of generation and transmission expansion were very effective.

During the introduction of competitive mechanism into electricity generation and retailing, electricity transmission and distribution are considered to be monopolies thus should be regulated, targeting to prevent network companies from taking advantages of their privileged positions [5]. Under this circumstance, the main objective of transmission network planning is to provide a non-discriminatory and competitive environment for all network users, however the main criteria remain as system reliability [58]. Under deregulated environments, transmission network planning become more difficult as much attention must be paid to deal with the uncertainties in generation expansion and demand growth. The solution adopted in many countries for transmission planning is to develop an indicative expansion plan, providing the information on possible future generation/demand growth and potential network expansion [5].

Taking the UK for example, the core criteria of transmission network planning are based on the fundamental reliability considerations in respect of meeting system peak demands. This criteria remain unchanged as the titles of network planning rules change [59, 60], from CEGB planning criteria since late 1940s, to National Grid SQSS (Security and Quality of Supply Standard) in early 1990s, to Great Britain SQSS in 2005.

The required transmission capabilities for Main Interconnected Transmission System (MITS) are solely based on a security planned transfer condition, which basically develops transmission networks that facilitate conventional generation to supply demand during the period of system peak.

This reliability based planning criteria are based on and inherently assume the reliability performance characteristic of conventional generators, i.e. they are predictable, controllable and reliable to generate as long as required. In other words, it requires that transmission capacity is sufficient to absorb simultaneous maximum output from conventional generators, without considering the influences of renewable generation [61].

2.3.2 Transmission Planning for a Low Carbon Future

Nowadays, transmission network planning becomes more challenging, even the fundamental principle of reliability consideration is shaken [20]. It requires new investments to be justified on an economic basis [62], i.e. the trade-offs between operational and investment costs.

Major challenges come from the large deployment of renewable generation. European Union has committed to sourcing 20% of its energy from renewables by 2020 [14]. Particularly, the United Kingdom has committed to meeting a target of 50% of electricity in Scotland and 15% of energy in the UK from renewables by 2020 [63]. However, renewable generators have very different operation characteristic when compared to conventional generators. Correspondingly, their impacts on network investment decisions are also different to those of conventional generators [64]. The integration of renewable generators into transmission networks often require more, but under-utilized transmission capacities to be built [58].

However, the existing transmission planning criteria were devised for power systems without significant penetration of renewable generation. Renewable generation have low load factors due to their intermittent features [61]. Therefore, renewable generation can displace the energy produced by conventional generation, but their abilities in displacing conventional capacity are limited. Conservatively following the existing transmission planning criteria would lead to overinvestment of transmission networks.

In the undergoing low carbon transition, integrated reliability and cost-benefit criteria in transmission planning are required. The cost-benefit criteria refer to a compromise between operational costs and investment costs in determining the optimal transmission expansion plan, i.e. the level of transmission congestion cost is used as the driving indicator for the need of transmission network expansion [58]. The cost-benefit criteria of transmission planning are shown in Figure 2-1 [65].

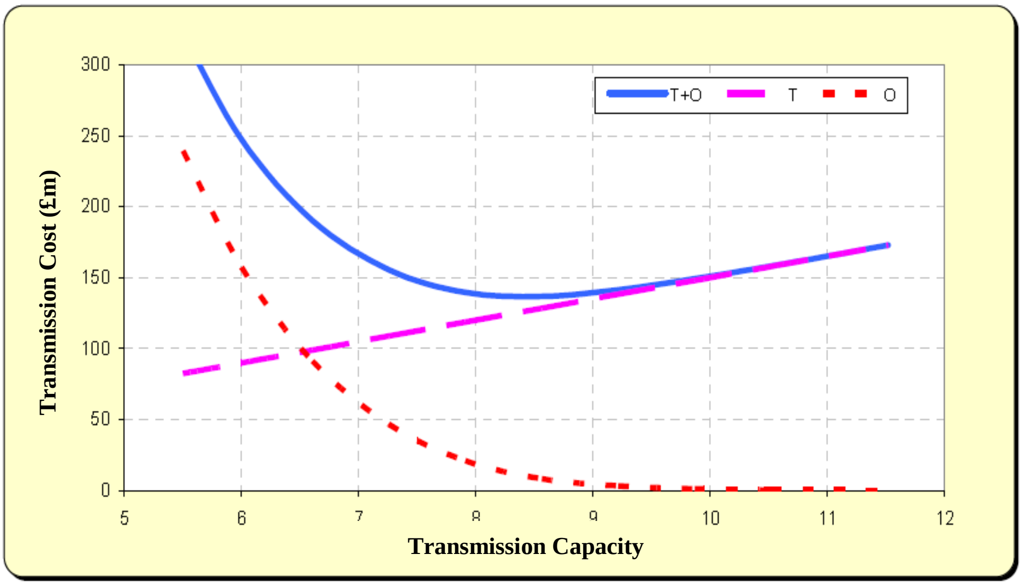

Figure 2-1 Trade-offs between Investment Costs and Congestion Costs

In Figure 2-1, the horizontal axis stands for transmission capacity. The vertical axis stands for transmission costs (investment costs and/or operational congestion costs). In Figure 2-1, T stands for transmission investment costs, O stands for operational congestion costs, and T+O stands for the total transmission costs. Pink dashed line stands for increasing transmission investment costs with the increase of transmission capacity. The red dashed line stands for decreasing operational costs (constraints/congestion costs) with the increase of transmission capacity. The solid blue line stands for the sum of investment costs and operational costs, showing a U-shaped curve.

It is apparent that too little transmission capacity (the left side of Figure 2-1) results in high congestion costs. Under this circumstance, renewable generation is curtailed and expensive conventional generation are substituted. On the other hand, too much transmission capacities (the right side of Figure 2-1) lead to no congestion. In this case, the marginal reduction in congestion costs is far less than the marginal costs of building transmission capacities but the overall costs largely increases, i.e. transmission investments are economically inefficient thus transmission congestions should be tolerated. The optimal transmission capacity is where there is a minimum total transmission cost, i.e. the valley point of the blue line.

Particularly in the UK, increasing integration of renewable generation have triggered a review of the fundamental principles in Great Britain SQSS [66-68]. It was recognised that the SQSS criteria determining the minimum transfer capabilities for the boundaries of the Main Interconnected Transmission System (MITS) were developed for power systems assumed to have only thermal generators. Therefore, they were unlikely to be suitable for power systems with a mix of generation including renewables [63]. The existing SQSS criteria would lead to transmission overinvestment when renewable generators are located in an exporting area or to underinvestment and a significant increase of transmission congestions when renewable generators are located in an importing area.

The review of Great Britain SQSS recognises the characteristic of renewable generation [67, 68]:

- Majority of them are located far away from demand centres, thus requiring significant network reinforcements.

- Majority of them are difficult to control their outputs, which can only be predicted with limited certainty.

Correspondingly, the required transfer capabilities for the MITS are modified to be based on dual conditions [69]:

- Security planned transfer condition

Security planned transfer condition remains the principles in previous GB SQSS, aiming to develop transmission networks that facilitates conventional generation to supply demand during the period of system peak. In this condition, renewable generation are assumed not to be contributing in supplying demand.

- Economy planned transfer condition

Economy planned transfer condition employs a similar procedure as security planned transfer condition, with difference in the scaling factors for various generation technologies. Table 2-3 states the generation scaling factors in security condition and economic condition [68]. The "varying" scaling factors in both conditions are used to scaling total generation capacity down to the level of peak demand.

Table 2-3 Generation Scaling Factors in GB SQSS

	Security Planned Transfer Condition	***Economy Planned Transfer Condition***
Intermittent	0%	70%
Nuclear & CCS	Varying	85%
Interconnector	Varying	100%
Hydro	Varying	Varying
Pumped Storage	Varying	50%
Peaking	Varying	0%
Conventional	Varying	Varying

The rationale of the economic condition is that the determined transfer capacity through this kind of deterministic approach can provide a high-accuracy approximation of the results from an exhaustive cost-benefit analysis (CBA) [68]. Economic condition is essentially a pseudo cost-benefit analysis, which is verified to be able to achieve the right balance between the cost of investing transmission networks (construction) and the cost of operating congested power system (congestion and losses) [66].

Afterwards, between the required transfer capacities for the same boundary under security condition and economic condition, the higher requirement is compared with the existing transfer capacity to determine whether reinforcements are need or not [69].

2.4 Recent Developments in Transmission Charging for a Low Carbon Future

To address the challenges in transmission planning, an effective solution is to develop indicative transmission expansion plans, providing network users with the information about predicted future generation/demand growth and potential network expansion. For example, the EU's "Ten Year Network Development Plans and Regional Investment Plans" from ENTSO-E [7], and the UK's "Electricity Ten Year Statement" from National Grid [70].

Moreover, transmission charges, which are to cover transmission costs, can take the responsibility to provide economic signals to enable network users to make informed commercial decisions about where to situate new generation and when to adjust or close existing generation, which would in turn influence the required transmission investments and support to develop an economically efficient power system at the lowest cost [71].

In this section, the recent developments in transmission charging are introduced, both broadly in the EU and particularly in the UK.

2.4.1 Harmonization of Transmission Charges in the EU

The increasing interconnection and integration of the European energy market increase the risk that different transmission charging structures across the EU would distort the free competition of generators from different countries and the investment decisions of new transmission infrastructure [45]. Against this background, the harmonization of transmission charges in the EU started.

Regulation (EC) No 714/2009 and Regulation (EU) No 838/2010 clearly state EU's opinions that "*determine appropriate rules to lead a progressive harmonisation of the underlying principles for the setting of transmission charges…*" and "*monitor the appropriateness of transmission charges, taking particular account of their impact on* *the transmission capacity needed to achieve Member States' targets for the promoting of energy from renewable sources ...*" [72, 73].

EU Agency for the Cooperation of Energy Regulators (ACER, established in 2007), whose main task is to provide a framework for national regulators to cooperate and oversight the cooperation among Transmission System Operators, deems the importance that "*transmission charges cost-reflective…., to the extent possible, in a harmonised way across Europe*". [45]

In the EU, the structure of transmission charges differ much in the aspects of allocation to energy or capacity, to generation or demand [74, 75]. Currently, the majority of EU Member States only targets transmission charges to demand, in effect socializing the transmission costs. This in part has historical reasons due to the vertically integrated nature of European utilities before deregulation. Only a few countries have geographical varying transmission charges (such as the United Kingdom).

Consequently, the harmonization of transmission charges across the EU lead to a proposition that all countries turn to socialized transmission charges [74, 75]. Paper [75] clearly states that the UK should be against this kind of harmonization, which is obviously a step backward of the current transmission charging arrangements that are advanced in providing locational and cost-reflective transmission charges.

Moreover, learning from the USA experience (mainly LMP method) requires fundamental changes in the UK's electricity trading arrangements and transmission charging structure, which are not widely acceptable by the UK government and the power industry [76]. Therefore, this thesis pays much attention to the developments of electricity network charging methods in the UK.

2.4.2 Improved Investment Cost Related Pricing (ICRP) Method

The United Kingdom's power industry is experiencing an unprecedented change, i.e. connecting large amount of renewable generation to electricity networks to meet ambitious targets against climate change. Meanwhile, it is however full of doubts whether the transmission charging arrangements in place could still facilitate power system in continuously providing reliable and economic electricity supply for both the existing and future customers. Against this background, Project TransmiT was launched by Ofgem

[77]. As the result, an improved ICRP method was approved to derive transmission charges for a low carbon future [78].

This section briefly introduces the evolution of Project TransmiT, carefully explains the modifications in improved ICRP method and critically raises several concerns about the effectiveness of this method.

2.4.2.1. Evolution of Project TransmiT

- In September 2010, Ofgem launched Project TransmiT and called for evidence on the issues that should be included [77].

- In January 2011, Ofgem explained that the scope of Project TransmiT would be electricity connection issues and transmission charging arrangements [79].

- In May 2011, Ofgem launched a Significant Code Review [76], which concluded that there should not be fundamental changes in the GB electricity trading arrangements and the structure of transmission charging.

- In July 2011, Ofgem established a technical working group to identify the potential options for TNUoS charges [80]. The potential options include:

  - ✓ Status Quo, which refers to retain the current charging method.

  - ✓ Improved ICRP method, which refers to incremental changes in the existing method, aiming to better reflect the different impacts that different types of generators have on transmission costs.

  - ✓ Socialisation, which refers to recover transmission costs through a uniform charge, whatever the type or location of generators.

- In December 2011, Ofgem consulted the assessments on potential options and stated its initial views to support the improved ICRP method [80].

- In May 2012, Ofgem directed National Grid to modify TNUoS charging method [81].

- In June 2013, a final modification report was submitted to Ofgem [82].

- In July 2014, Ofgem approved this modification after two consultation [78], which allow National Grid to implement the proposed modification from 1st April 2016.

2.4.2.2. Modifications in Improved ICRP method

Generally, the improved ICRP method aims to enhance the cost reflectivity of TNUoS charges in reflecting how and when generators use transmission networks and their impacts on transmission costs, especially for renewable generation, who have lower impacts on transmission investments than conventional generation [78].

In the improved ICRP method, the key principles of the Investment Cost Related Pricing method still apply. However, it changes the locational element in TNUoS charges for generators, aiming to differentiate different types of generators.

Table 2-4 presents the major modifications in the improved ICRP method [78].

Table 2-4 Components of Locational Element in Improved ICRP method

Component of locational element	*Conventional Generators*	*Renewable Generators*
Peak Security	£/kW×TEC +	-
Year Round- non shared	£/kW×TEC +	£/kW×TEC +
Year Round -shared	£/kW×TEC×ALF	£/kW×TEC×ALF

In Table 2-4, *TEC* stands for Transmission Entry Capacity, which is the maximum amount of electricity a generator is allowed to export to the transmission networks. *ALF* stands for generator annual load factors, which are calculated based on their historical generation outputs in the past 5 years.

Major modifications in the improved ICRP method are in the following aspects:

1. **Peak Security and Year Round**

Instead of employing a signal scenario of peak demand in the existing ICRP method (Detailed introduction in section 2.2.2.2.), the improved ICRP method employs two scenarios: Peak Security and Year Round.

Similar to scaling down the total generation capacity to meet peak demand in the existing ICRP method, the improved ICRP method creates two peak demand conditions (Peak Security and Year Round) and scales generation capacity differently under each condition with the same scaling factors that are employed in transmission network planning (Table 2-3) [69].

In the improved ICRP method, the Peak Security scenario is intended to reflect the capacity required for reliable supply during the period of system peak, whilst the Year Round scenario is intended to reflect the capacity required for economic network planning, coming from the trade-off between investments cost and operational costs.

Only conventional generators are charged for the Peak Security scenario, which is aligned to the Security planned transfer condition and reflects that intermittent generators are not assumed to contribute to meeting peak demand.

Both conventional generators and renewable generators are subject to Year Round scenario, which is aligned to the Economy planned transfer condition and reflects the fact that all generators contribute to meeting varying demands all around the year.

A particular transmission branch is allocated to one scenario or the other, depending on which scenario leads to a high power flow on that branch.

2. “Shared” and “Non-Shared”

The Year Round components are further divided to “shared” and “non-shared” parts. The split is based on the penetration level of low carbon generation in a particular area. If the level of low carbon behind a boundary is 50% or less, then entire Year Round component is ‘shared’. Once this percentage exceeds 50%, an increasing proportion is considered as ‘non-shared’.

This modification is to reflect that generators in areas dominated by renewable generation tend to drive higher levels of congestion costs and therefore investments than if there are various types of generators in an area.

3. Annual Load Factor

For the 'shared' part of Year Round components, the initial transmission charges are multiplied by a generator's average annual load factor for the last five years. This modification is to reflect how different generators drive different levels of transmission investments.

This modification recognises that numerous factors from generation, transmission network and demand sectors have various impacts on congestion costs and therefore required investments. However, the improved ICRP method chooses to use a simple proxy, generator's annual load factor, to represent the effects of all these factors.

2.4.2.3. Concerns about Improved ICRP method

By approving these modifications, Ofgem is of the view that the improved ICRP method can [78]:

- better reflect the impacts of different network users on transmission costs, because it is a closer approximation of the transmission planning criteria.
- make transmission charges more stable and transparent, thus reducing barriers to entry and facilitating effective competition.
- keep an appropriate balance between accuracy and transparency.
- give a better performance under latest energy policies.
- better meet Ofgem's principle objective to protect the interests of existing and future consumers.

However, there are several concerns about the improved ICPR method.

- Peak Security and Year Round scenarios

The design of Peak Security and Year Round scenarios keep a high consistency with the Security planned and Economy planned conditions. However, the main objective of transmission planning is to identify the optimal transmission capacity to achieve reliability and economic efficiency. Meanwhile, the main objective of transmission charging is to provide cost-reflective signals reflecting network users' impacts on transmission investments. Duplicating the deterministic rules of transmission planning to transmission charging cannot guarantee that the correct signals are provided to network users [83], as the scaling factors in the improved ICRP method only aims to give appropriate transmission capacity through a pseudo cost-benefit analysis rather than accurately presently the contributions to transmission investments from different network users.

- Annual load factor to differentiate generation technologies

The improved ICRP method employs annual load factors to differentiate generation technologies, basically relying on the assumed linearity that generators with high load factors would have high impacts on the resultant congestion costs and therefore required investments. However, this linearity may not be applicable for all generators or for all locations. Ofgem also recognises this in [78], stated as "…*in reality the impact of individual generators may differ from that estimated* …".

2.4.3 Application of LRIC Method in Transmission Networks

Long-Run Incremental Cost (LRIC) pricing method was originally developed by University of Bath jointly with Ofgem and Western Power Distribution [84]. Currently, it is the core principle of charging methods for EHV (Extra High Voltage) distribution networks of major Distribution Network Operators in the UK, such as Western Power Distribution and UK Power Networks [85].

LRIC method can reflect not only the distance that electricity travels to meet demand, but also the degree of utilization of the travelling path. Firstly, it exams the impacts of additional nodal injection on the investment time horizons for all components that support the travelling path. Afterwards, these impacts are translated into locational charges, which are essentially the changes in the present values of future reinforcements for these components.

This section carefully explains the basic principles of LRIC method, briefly introduces its further improvements, and highlights the possibility to extend its application to transmission networks.

2.4.3.1. Basic Principles of LRIC method for Distribution Networks

LRIC method innovatively identifies the presence of unused capacity in distribution networks, and recognizes that the investment time for a network component would be when its loading level reaches its rated capacity. It assumes that for all components affected by an additional injection, either generation or demand, there would be a cost if their investments are advanced or a benefit if their investments are deferred. Given the investment costs for these components and a chosen discount rate, there would be changes in the present values of these investments. LRIC method assigns these changes as the distribution use of system charges for network users.

The main steps of LRIC method are:

1. **Investment time horizon**

For a network component *l*, such as a circuit, its investment time horizon t_{inv} is determined by when the power flow PF_l along it reaches its rated capacity RC_l.

$$RC_l = PF_l \times (1+r)^{t_{inv}} \qquad \text{(Eq. 2-5)}$$

where r is the demand growth rate.

Therefore, its investment time horizon t_{inv} is

$$t_{inv} = \frac{\ln RC_l - \ln PF_l}{\ln(1+r)} \qquad \text{(Eq. 2-6)}$$

LRIC method assumes that when reinforcements are required, a duplication of this network component is taken.

2. **Changes due to additional injection**

If an additional nodal injection Δp_i is added to node i, the power flow along network components would change and consequently their investment time horizons.

For network component *l*, its investment time horizon changes from t_{inv} to t'_{inv}, where t'_{inv} stands for the new investment time horizon due to the additional nodal injection Δp_i. Meanwhile, the present values (Briefly a future amount of money that has been discounted to reflect its current value, reflecting the time value of money. Full definition of present value is given in Appendix A-2.) of its future reinforcements become

$$PAIC_l^{t_{inv}} = \frac{AIC_l}{(1+d)^{t_{inv}}} \quad \text{(Eq. 2-7)}$$

$$PAIC'^{t'_{inv}}_l = \frac{AIC_l}{(1+d)^{t'_{inv}}} \quad \text{(Eq. 2-8)}$$

where AIC_l is the annualized investment cost for network component l, $PAIC_l^{t_{inv}}/PAIC_l^{t'_{inv}}$ is the present value for the reinforcement of network component l for year t_{inv} / t'_{inv} and d is the fixed discount rate.

3. Long-run incremental cost

The LRIC cost from network component l due to additional injection Δp_i at node i is the difference in the present values with and without Δp_i:

$$\text{LRIC}_{l,i} = PAIC'^{t'_{inv}}_l - PAIC_l^{t_{inv}} \quad \text{(Eq. 2-9)}$$

The total LRIC cost for node i is the summation of LRIC costs from all network components.

$$\text{LRIC}_i = \frac{\sum_l LRIC_{l,i}}{\Delta p_i} \quad \text{(Eq. 2-10)}$$

For EHV network users, their distribution use of system charges are determined by multiplying their sizes with the LRIC at their connection points.

LRIC method has the following merits:

- respecting the discrete size of network components and inherently their indivisibilities by assuming a duplication for future reinforcements;
- recognizing the ‘distance’ that electricity travels to meet demand by summing up the impacts on all network components;
- reflecting the degree of utilization of network components, which could be defined as PF_l/RC_l;
- providing forward-looking charges by looking into network investments in a future time;

2.4.3.2. Continuous Improvements of LRIC method

On the basis of the aforementioned basic principle, further improvements of LRIC method include:

- considering different demand growth rates in LRIC method [86]
- considering the impact of network contingencies in LRIC method [87]
- the long-term benefits for interruptible load schemes [88]
- LRIC method based on fault current calculation [89]
- LRIC method based on nodal voltage spare capacity [90]
- the application of LRIC method in HV distribution networks [91]
- the application of LRIC method in large-scale system [92]

2.4.3.3. LRIC method for Transmission Networks

The fundamental innovation in LRIC method for distribution networks is that it can reflect the essence of distribution network investments, i.e. network components have to be reinforced when their loading levels reach their rated capacities. This works well for passive distribution networks, in which network topology is simple and demand have to be met through the circuit they connected.

However, this is not the case for transmission networks, in which Transmission System Operators (TSO) have the capabilities to carry out active congestion management. In other words, when the power flow along a transmission branch reaches its rated capacity, it is not inevitable that this branch must be reinforced. TSO can re-dispatch generation to avoid power line overheads and securely meet demand. But of course, congestion management is at the expense of an increase in operational costs.

The essence of transmission investments under the economic criteria are to identify when the operational costs due to generation re-dispatch exceed the investment costs due to network upgrades. This is where the principle of LRIC method may apply. The application of LRIC method in transmission networks should focus on the investment time horizons of transmission branches.

Paper [55] is a recent attempt to apply the principle of LRIC method into transmission charging. It innovatively acknowledges the trade-offs between short-run operational costs and long-run investment costs in transmission investments under the economic criteria, and introduces this into transmission charging.

However, it is not mature because of the following drawbacks:

- It is based on a simple two-bus power system, thus cannot reflect the complex topology of transmission networks. Moreover, as there is only a branch in the demonstration system, it fails to explain how to determine the investments time horizons for different branches in transmission networks.

- It only considers the situation when an area (a node in the two-bus power system) is dominated by a generation technology, which however is not the case for transmission networks. In the low carbon transition, generation mix become diverse and different generation technologies are deployed at the same location.

- It fails to recognise that operational costs are the result of varying demand throughout the year. Not like distribution networks, the magnitude of peak demand does not have a decisive influence on the investment decision in transmission networks.

2.5 Essential Features of Transmission Charging for a Low Carbon Future

Although much efforts have been made to develop appropriate transmission charging methods for low carbon power systems, the recent developments still have one kind or another disadvantages. Based on the reviews presented in previous sections, improvements can still be made in the following aspects:

1. **Economic efficiency**

Transmission charges derived from the existing charging methods provide economically inefficient signals for network users in low carbon power systems, especially for renewable generation. This would lower the utilization efficiency of existing networks. Even worse, this would lead future generation expansion to wrong locations as the resultant investment costs due to generation expansion at one location will not reasonably allocated to the connected generators but inefficiently among all generators. The influence of transmission charges in guiding the appropriate behaviours of network uses should be enhanced.

2. Cost reflectivity

Transmission charging methods for low carbon power system should reflect the impacts of system operation on transmission investments, thus reflecting the trade-offs between operational costs and investment costs. In order to achieve a high-level cost reflectivity, the key drivers for operational costs, from both generation and demand sectors, should be carefully considered.

3. Promoting competition

Transmission charging methods for low carbon power systems should identify the different features between various network users and remove the barriers for fair competition.

4. Accommodating policies

Governments set ambitious targets in renewable energy utilization and emission reduction. However, existing transmission charges may obstruct the development of renewable generation. Transmission charging methods for low carbon power systems should provide network users with incentivizes to contribute to achieving these targets.

Unfortunately, the compromise between these principles during the developing of transmission charging for a low carbon future will be inevitable and must be carefully handled.

2.6 Chapter Summary

This chapter firstly provided an overview on the roles and principles of transmission charging. It summarized the existing electricity network charging methods and presented the international experience on transmission charging.

Then, this chapter introduced the significant changes in the criteria of transmission planning under the low carbon transition of the power industry.

Afterwards, this chapter listed the recent developments in transmission charging methods and outlined their strong points and weakness. Based on these, it proposed the essential features of transmission charging for a low carbon future.

In this thesis, the research will focus on developing Transmission Use of System (TUoS) charging methods to recover investment costs of shared transmission networks in the low carbon transition of the power industry. Several advanced methods are developed and detailed procedures are given in the following chapters.

Chapter 3

Key Drivers and Key Conditions For Transmission Investments

THIS chapter identifies the key drivers and key conditions for transmission investments under the economic criteria, thus inspiring the developing of TUoS charging methods for a low carbon future.

3.1 Introduction

In conventional power systems, transmission investments are dictated by peak demand, i.e. providing sufficient transmission capacities to meet the increasing peak demand. Under this circumstance, transmission investments are mainly reliability driven [57]. In other words, the connection of new network users will normally trigger a system impact analysis to assure that system reliability is maintained, otherwise new transmission capacities are built.

In the low carbon transition, it is not economical to provide sufficient transmission capacities for the simultaneous maximum outputs from renewable generators [93, 94]. This is because the outputs of renewable generation are subject to the availability of renewable resources, and in very small chance, renewable generators can reach their maximum outputs simultaneously. Even in some cases when the total outputs are higher than the transmission capacities, the superfluous electricity from renewables could be abandoned, as the curtailing of renewable generation for a short period is economical when compared with the investing of excess transmission capacities that may become idle for most of time.

Transmission investments for low carbon power systems become not only reliability driven to meet peak demand, but also economically driven to ensure investment efficiency, i.e. basing on the trade-offs between the benefits from network upgrades and the costs of network upgrades [64]. Therefore, how to quantify the benefits of network upgrades becomes the core question in understanding transmission investments under the economic criteria and developing charging methods for low carbon power systems.

Transmission network upgrades can eliminate transmission congestions, consequently congestion costs caused by transmission congestions. Roughly speaking, the comparison between the benefits of network upgrades and the costs of network upgrades can be replaced by the comparison of the congestion costs due to capacity shortage and the investment costs due to network upgrades. Transmission congestion costs provide the approach to quantify the benefits of network upgrades [95]. Moreover, the key drivers for the increase of congestion costs are the factors that trigger the transmission investments under the economic criteria. And the key conditions for congestion costs can provide an overview of when and where transmission investments are required.

The work in this chapter explains the detailed calculation process of congestion costs by employing a simple power system. It helps to identify the key drivers for transmission investments under the economic criteria, among various factors from generation, network and demand sectors (Section 3.2). The work in this chapter also explores the spatial and temporal distribution of transmission congestions, aiming to identify the key conditions for transmission investments (Section 3.3).

3.2 Identifying Key Drivers for Transmission Investments under the Economic Criteria

3.2.1 Study Framework

This study employs a simple power system to explain the occurrence of transmission congestion and the calculation of congestion cost. A clear understanding of these will help to understand the work presented later in this thesis.

After explaining the calculation of congestion cost, this study investigates the influences of various factors on the annual congestion cost, aiming to identify those that are key drivers for transmission investments under the economic criteria thus should be considered in the developing of TUoS charging methods.

This study acknowledges that congestion costs are not solely determined by a single factor, but are shaped by various factors from generation, transmission network and demand sectors. These factors are summarized in Table 3-1.

Table 3-1 Factors that Impact Congestion Cost

Generation Sector	*Transmission Sector*	*Demand Sector*
Generation capacity	Transfer capacity	Demand peak
Generation availability	Topology	Demand profile
Production cost	Length	
Location		

3.2.2 Test System

The test system used for this study is illustrated in Figure 3-1.

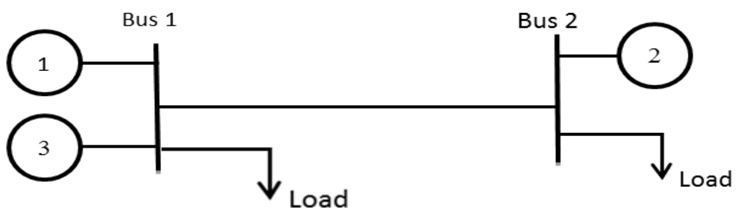

Figure 3-1 Two Bus Test System

Generation parameters for the test system are given in Table 3-2.

Table 3-2 Two Bus Test System Generation Parameters

Generator	*Connection Bus*	*Technology*	*Generation Capacity (MW)*	*Production Cost (£/MWh)*
G_1	Bus 1	Thermal	150	25
G_2	Bus 2	Thermal	50	40
G_3	Bus 1	Wind	50	0.01

Transmission capacity is assumed to be 100MW. The demand peaks at Bus 1 and Bus 2 are assumed to be 30MW and 150MW respectively.

Hence, Area 1, which is associated with Bus 1, has a high generation capacity but a low demand. Conversely Area 2, which is linked to Bus 2, has a low generation capacity but a high demand.

Other assumptions for this test system are:

- Thermal generators are available whenever required subject to their rated capacities;
- Wind generation output is derived from the Met office wind speed data for 2011 [96];
- Transmission losses are not considered;
- Demand profile is taken from historical data for the Great Britain power system in 2011 [97];
- Demand profiles for each bus are the same, which implies that the peak demand at Bus 1 is simultaneous with the peak demand at Bus 2.

3.2.3 Calculation Process of Congestion Cost

3.2.3.1. The Definition of Congestion Cost

If the limit in transmission capacity is not considered, demand would be met by G_3 first, then G_1, at last G_2, basing on their economic efficiencies (generation production costs). The direction of power flow along the transmission branch is from Bus 1 to Bus 2, but its magnitude may exceed the rated transmission capacity (100MW). Under this circumstance, the total generation cost is the minimum.

When the limit in transmission capacity is considered, G_3 and G_1 are also first dispatched. However, when the power flow along the transmission branch exceeds 100MW, transmission branch would be overloaded and transmission congestions occur. To avoid the serious consequences of transmission branch overloading, transmission congestions must be resolved. To do so, expensive generator G_2 is dispatched to replace the outputs of cheap generators connected at Bus 1, consequently to reduce the power flow along transmission branch. Under this circumstance, as electricity generated by G_2 is more expensive, the total generation cost is higher that the case when transmission capacity limit is not considered.

The increment in total generation costs with and without considering the transmission capacity limit is defined as the **congestion cost** incurred by transmission congestion [98].

3.2.3.2. The Calculation of Congestion Cost

In this thesis, the simulation of calculating congestion cost employs the DC optimal power flow analysis in Matpower [99]. Matpower is a Matlab Power System Simulation package developed by Cornell University and is able to execute economic generation dispatch via optimal power flow (OPF) analysis. The latest version is Matpower 5.1.

The congestion cost (CC) for one settlement period (0.5 hour) is calculated based on two economic dispatches in Matpower. The first one doesn’t consider the transmission capacity limits, conversely the second one considers. The difference in the total generation costs of these two dispatches is the congestion cost for this settlement period. Congestion cost is equal or higher than zero.

The annual congestion cost is the sum of congestion costs for 17520 settlement periods over the course of a year (1 settlement period per 0.5h, thus 2×24×365=17520 in a year). A statistical probability based approach is employed to improve the computational efficiency in calculating annual congestion cost. (Details are given in Appendix A-3)

3.2.4 Various Factors' Impacts on Annual Congestion Cost

3.2.4.1. Generation Sector

In reliability driven transmission investments, the major factor to be considered from generation sector is the generation capacity, as the majority of conventional generation are controllable thus available whenever required. For transmission investments under the economic criteria, the main trigger is the increasing congestion cost, which is the result from the combination of generation capacities, production costs and availabilities (controllable or intermittent).

In order to examine the impact of generation technology on annual congestion cost, the installed capacity of wind generation in the test system is increased from 10MW to 150MW, resulting in an increasing wind penetration level from 4.7% to 42.8% (calculated by dividing wind generation capacity with the total generation capacity). Meanwhile, the installed capacities for other generation technologies remain unchanged. Figure 3-2 illustrates how annual congestion cost changes with increasing wind penetration level.

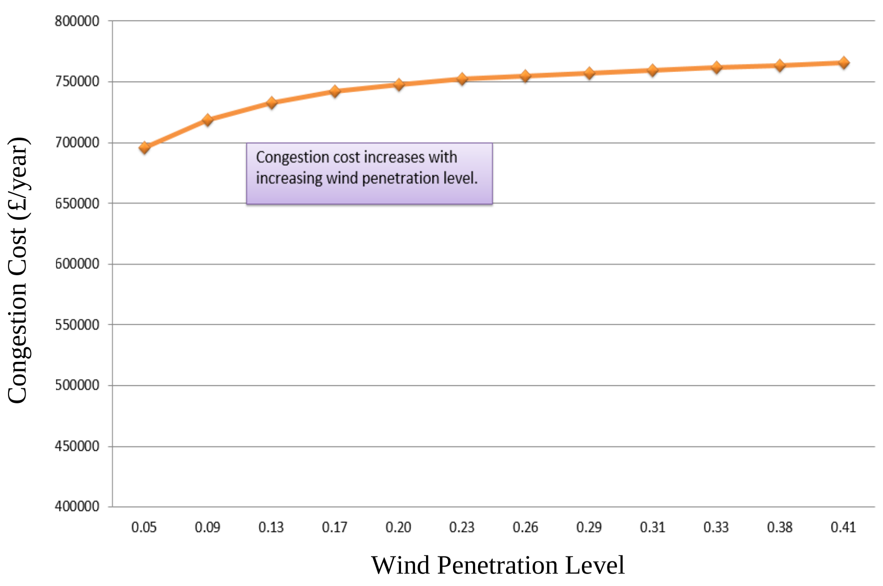

Figure 3-2 Impacts of Wind Penetration on Annual Congestion Cost

When the wind penetration level is lower than 30%, annual congestion cost increases slowly with the increasing of wind penetration level. This is because the limit of transmission capacity constrains renewable generation. After the penetration lever is high (over 30%), transmission capacity has be dominated by renewable generation, thus the annual congestion cost becomes relatively stable.

If the increasing generation capacity comes from expensive thermal generator G_2, the annual congestion cost will not change as its capacity is already redundant for the system (Generator G_2 is the most expensive generator, thus its capacity increase will not be dispatched to meet demand in economic dispatch). If the increasing generation capacity comes from cheap thermal generation G_1, the annual congestion cost will not change, either. This is because that G_1 is located behind transmission congestion. There is no available transmission capacity for the expansion from G_1.

Generalising the results, it is apparent that the impacts of generation sector on annual congestion significantly depend on the generation technologies and generators' locations. Generators' connection locations to transmission networks have been considered in existing TUoS charging methods. But in a low carbon background, generation technology must be considered in the developing of TUoS charging methods.

3.2.4.2. Transmission Sector

In transmission sector, both transmission capacity and transmission topology can significantly influence the annual congestion cost. This is because, once the limits in transmission capacity are removed, neither transmission congestions nor congestion costs will occur.

The impact of transmission capacity on annual congestion cost is investigated by varying transmission capacity in 5MW steps from 100MW to 150MW. Figure 3-3 clearly shows that the increasing of transmission capacity can significantly reduce the annual congestion cost.

Therefore, transmission capacity is a key factor that should be considered in developing TUoS charging method. The literature review in Chapter 2 shows that the existing transmission charging methods (such as ICRP method) fail to reflect its importance in transmission charging. Hence, introducing the impacts of transmission capacity into TUoS charging is set as one of the main targets in this research work.

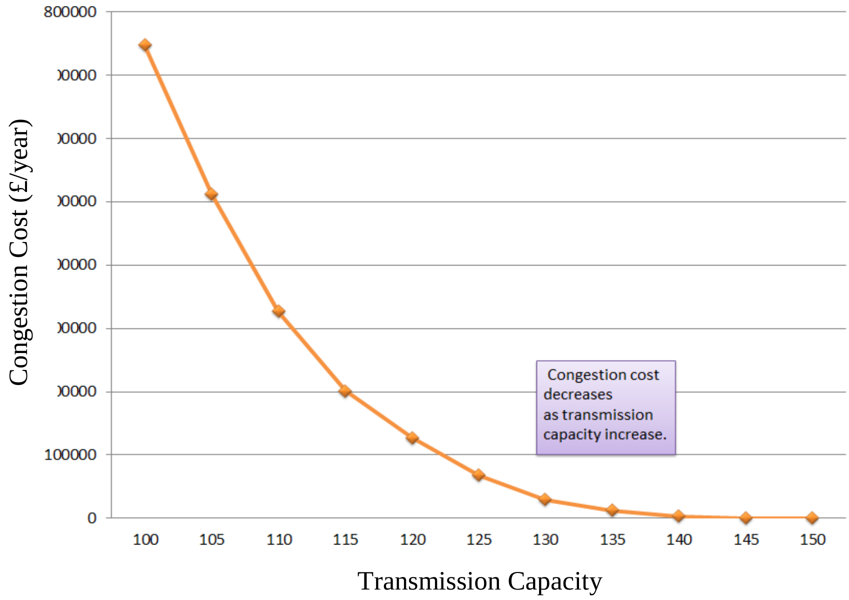

Figure 3-3 Impacts of Transmission Capacity on Annual Congestion Cost

3.2.4.3. Demand Sector

Previous transmission planning and charging methods emphasize the importance of demand peak. This is because under high carbon circumstance, power system that is able to satisfy the system operation during demand peak will be able to satisfy system operation for the whole year. For transmission investments under the economic criteria, congestion costs that are the result of year-round system operation become the main trigger. Therefore, the influence of demand profile should be explored as it determines the year-round congestion costs.

Demand profile refers to the varying demand curve in a certain period of time. Eight demand profiles with same demand peak but increasing annual energy consumption are employed here. These demand profiles are represented by increasing demand load factors from 0.63 to 0.70 (achieved by increasing the probabilities of medium demand levels, such as demand level 3 - 6, please check Appendix A-3 for better understanding), which simulates the growth of electricity consumption in developed countries like the UK.

Figure 3-4 shows how the annual congestion cost increases as the demand load factor increases. It is apparent that even when the peak demands are the same, the resultant annual congestion costs largely vary with the changes in demand profiles, and consequently the required transmission investments in economic driven background. Hence, it is necessary to consider the influence of demand profiles in transmission charging methods.

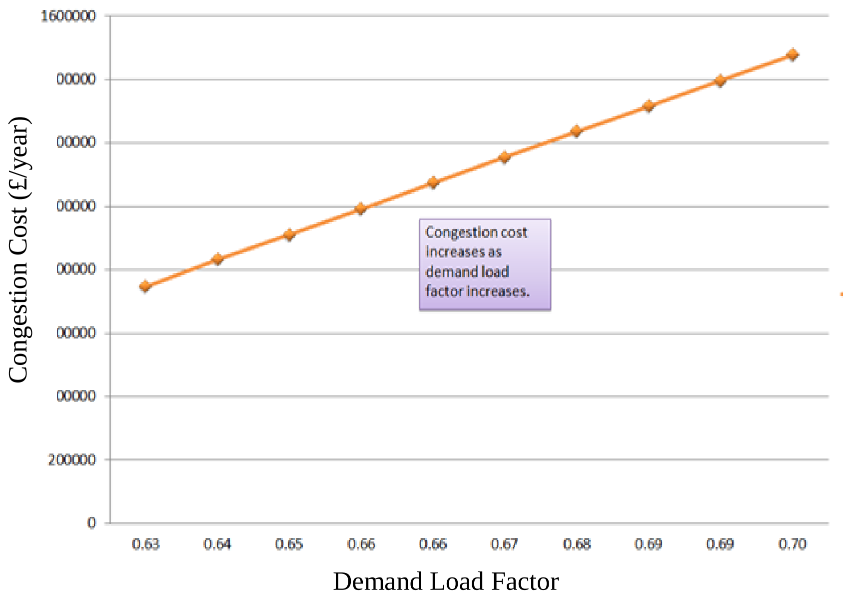

Figure 3-4 Impacts of Demand Load Factor on Annual Congestion Cost

3.2.5 Key Findings

This study acknowledges that the annual congestion cost is not determined by any single factor, but shaped by various factors from generation, transmission and demand sectors. And all of these factors combine to impact annual congestion costs in different ways, consequently the required transmission investments in an economic-driven background. Therefore, to provide cost-reflective signals, transmission charging methods should consider the varying influences of those factors.

In the generation sector, previous transmission planning and charging methods focus on generation capacity, assuming that all generation are available whenever required. But the diversity in generation technologies is ignored, which is however not acceptable for the transmission investments under the economic criteria. This study clearly shows that the expansion of different generation technologies have completely different influences on annual congestion cost, then will require different levels of transmission investments. It declares that generation technology is one of the key factors that must be considered in the developing of TUoS charging methods for low carbon power systems.

In the transmission network sector, the study clearly shows that transmission capacity significantly influences the annual congestion cost, consequently the required transmission investments. Therefore, transmission capacity should be a key factor in developing TUoS charging method. However, the literature review in Chapter 2 shows that this work has not been done in the existing transmission charging methods. Introducing the impact of transmission capacity into transmission charging is one of the main targets in this research work.

In the demand sector, previous transmission planning and charging methods emphasize the importance of peak demand. This study explores the impact of varying demand profiles on annual congestion costs. Even the peak demand is the same, the annual congestion costs vary to a large extent, consequently the required transmission investments. It is apparent that transmission charging method for low carbon power systems should consider the influences of demand profiles.

In summary, in order to provide necessary economic messages in transmission charges, the impacts of generation technologies, transmission capacity and demand profiles should be considered in developing TUoS charging methods for a low carbon future.

3.3 Identifying Key Conditions of Transmission Investments under the Economic Criteria

3.3.1 Study Framework

This study aims to identify the key conditions for transmission investments under the economic criteria, i.e. where and when the transmission investments are required.

To achieve the purpose of this study, a three-bus power system that represents a simplified Great Britain power system is devised. All of its parameters are taken from real data, thus it is supposed to display an approximate overview of transmission congestions across a year.

The study firstly derives a congestion cost duration curve showing the degree (magnitude) of transmission congestions over17520 settlement periods, which is similar to the demand duration curve showing the degree of electricity consumption over a year. Then, this duration curve is further divided into five segments, representing different degrees of transmission congestions.

Afterwards, the characteristics of each segment in this congestion cost duration curve are examined. For each settlement period, the congestion cost is allocated to different boundaries. And the spatial distribution of transmission congestions between different transmission branches are analysed for each segment of the congestion cost duration curve. Furthermore, the temporal distribution of transmission congestions on the course of 24 hours in a day are counted for each segment.

By analysing the spatial and temporal distribution of transmission congestions, this study can show where and when transmission investments are required, thus inspiring the development of TUoS charging methods for the low carbon transition.

3.3.2 Demonstration System

This study employs a three-bus power system, which represents a simplified Great Britain power system, as shown in Figure 3-5.

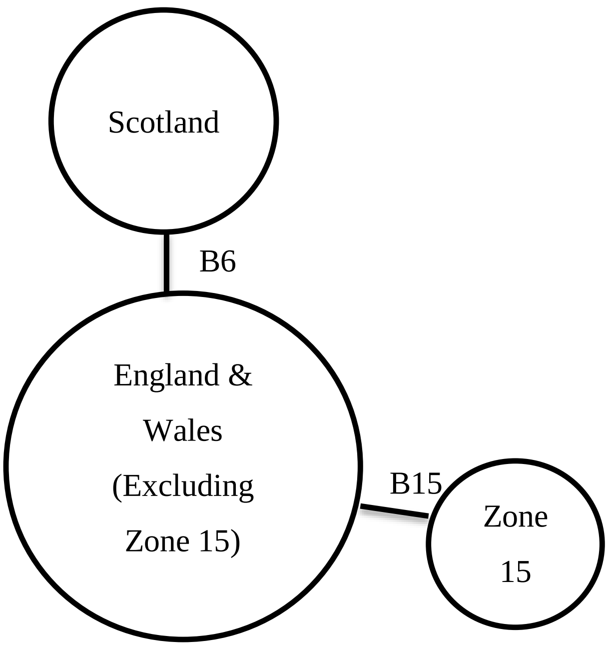

Figure 3-5 Simplified GB Power System

The GB transmission networks are separated into three areas: Scotland, England & Wales (excluding Zone 15), and Zone 15, by Boundary 6 (B6) and Boundary 15 (B15). B6 represents the network interface separating the transmission networks in Scotland, where huge renewable generation is deployed, and that in England & Wales, where large demand centres are located. B15 represents the network interface separating the transmission networks in England & Wales (excluding Zone 15) and that in the Zone 15, where the interconnectors from France and Belgium are connected to the GB system. Detailed information about B6 and B15 are available at National Grid's National Electricity Transmission System Seven Year Statement [100].

B6 and B15 together account for more than 80% of the GB transmission congestions [101]. Therefore, the three-bus power system can provide an approximation of year-round transmission congestions for the GB power system.

All the parameters for this demonstration system are taken from National Grid's Electricity Scenario Illustrator (ELSI) model for Great Britain power system [102]. The data in 2011 are adopted for this study.

Table 3-2 shows the generation parameters of the simplified GB power system.

Table 3-3 Generation Parameters for Simplified GB Power System

	Scotland		*England & Wales (exclude Zone 15)*		*Zone 15*	
Generation Technology	***Production Cost (£/MWh)***	***Generation Capacity (MW)***	***Production Cost (£/MWh)***	***Generation Capacity (MW)***	***Production Cost (£/MWh)***	***Generation Capacity (MW)***
Nuclear	6.5	2408	6.5	5713	6.5	832
CCGT	39.99	1001	45.35	19063	43.01	2769
Coal	37.63	2608	56.05	14757	45	2306
Oil/OCGT	130.14	539	171.17	4241	150	1122
Renewables	0.01	2700	0.03	848	0.02	357
Interconnector	0.01	385			0.001	2401

The assumptions made for generation sector are summarized as follows:

- Six generation technologies are chosen. Their installed capacities are scaled to satisfy the system peak without reliance on intermittent generation and interconnectors;
- Production costs are set as the typical values in ELSI model. Production costs in Scotland and Zone 15 are set lower than those in England & Wales;
- System reserves are not considered;
- Nuclear, CCGT, Coal, and Oil/OCGT are available whenever required subject to their capacities;
- Wind generation follows the historical wind speed data recorded by the MET office in 2011 [96];
- Interconnector behaviours are simulated as generation or demand while the GB system demand changes (only for simulation, not aligned with the reality):
  - When the GB demand is high (over 80% of peak demand), the interconnectors are deemed to be unavailable on the basis that other systems (France and Belgium) are also experiencing high demands;
  - When the GB demand is medium (from 50% to 80% of peak demand), the interconnectors operate at their rated capacities as generation;
  - When the GB demand is below 50% of peak demand, the interconnectors are recognised as demand, representing the exporting of power to France and Belgium.

Table 3-4 gives the transmission network parameters of the simplified GB power system, in accordance with their performance in 2011. In this model, transmission losses are not considered.

Table 3-4 Network Parameters for Simplified GB Power System

	Boundary 6	***Boundary 15***
Transmission Capacity (MW)	2800	6400

Table 3-5 shows the demand parameters of the simplified GB power system, with a total system peak demand of 58130 MW. Demand profiles for each zone are the same, as taken from the GB historical demand data for 2011 [97].

Table 3-5 Demand Parameters for Simplified GB Power System

	Scotland	***England & Wales (exclude Zone 15)***	***Zone 15***
Peak Demand (MW)	5697	50416	2107

In the employed demonstration system, the congestion direction on B6 is from Scotland to England & Wales, and on B15 from Zone 15 to England & Wales.

The same method of calculating congestion cost is employed as in section 3.2.3. At the settlement periods when only B6 is congested, the corresponding congestion cost is allocated to B6; similarly with B15. When both B6 and B15 are congested, the relevant power flows are used to allocate the congestion cost between B6 and B15.

$$CC_{B6} = \frac{(PF_{B6}-TC_{B6})}{(PF_{B6}-TC_{B6})+(PF_{B15}-TC_{B15})} \times total\ CC \qquad \text{(Eq. 3-2)}$$

$$CC_{B15} = \frac{(PF_{B15}-TC_{B15})}{(PF_{B6}-TC_{B6})+(PF_{B15}-TC_{B15})} \times total\ CC \qquad \text{(Eq. 3-3)}$$

where

CC	congestion cost
CC_{B6}	congestion cost for Boundary 6
PF_{B6}	power flow on B6 without considering capacity limit
TC_{B6}	transmission capacity of Boundary 6
CC_{B15}	congestion cost for Boundary 15
PF_{B15}	power flow on B15 without considering capacity limit
TC_{B15}	transmission capacity of Boundary 15

3.3.3 Results and Analysis

3.3.3.1. Year-round Transmission Congestion

For the demonstration system, the time-series congestion costs at 17520 settlement periods are calculated, based on the generation, transmission and demand parameters given in section 3.3.2. The same method of calculating congestion cost as in section 3.2.3 is employed. Furthermore, congestion costs are allocated between B6 and B15 by employing the method given in section 3.3.2.

Figure 3-6 shows the magnitude, location and time of transmission congestions for the simplified GB power system. Its horizontal axis stands for the 17520 settlement periods from 1st January 2011 to 31st December 2011. Its vertical axis gives the magnitude of congestion costs. A colour code is used to distinguish periods when only B6 is congested (blue) from times when only B15 is congested (red) and times when both boundaries are congested (green).

In general, Figure 3-6 illustrates that transmission congestions are not uniform across the system, i.e. congestion may either across B6 or B15 or both. Furthermore, the congestion across B6 is significantly more severe than those across B15. Besides these, no further useful information can be easily obtained. To get more, this study develops a congestion cost duration curve.

3.3.3.2. Congestion Cost Duration Curve

Figure 3-7 gives the congestion cost duration curve, which is the total congestion costs on B6 and B15. It is constructed by rearranging the congestion costs observed in each settlement period from the highest to the lowest. Its horizontal axis has no practical meaning but only counting the settlement periods from 1 to 17520. Its vertical axis gives the magnitude of congestion costs.

In Figure 3-7, the adjacent points along the duration curve imply similar congestion costs, thus representing similar degrees of transmission congestions. It is apparent that extremely severe transmission congestions, expressed by high congestion costs, only occur for a very small duration in a year. After those severe transmission congestions, congestion cost declines exponentially to zero.

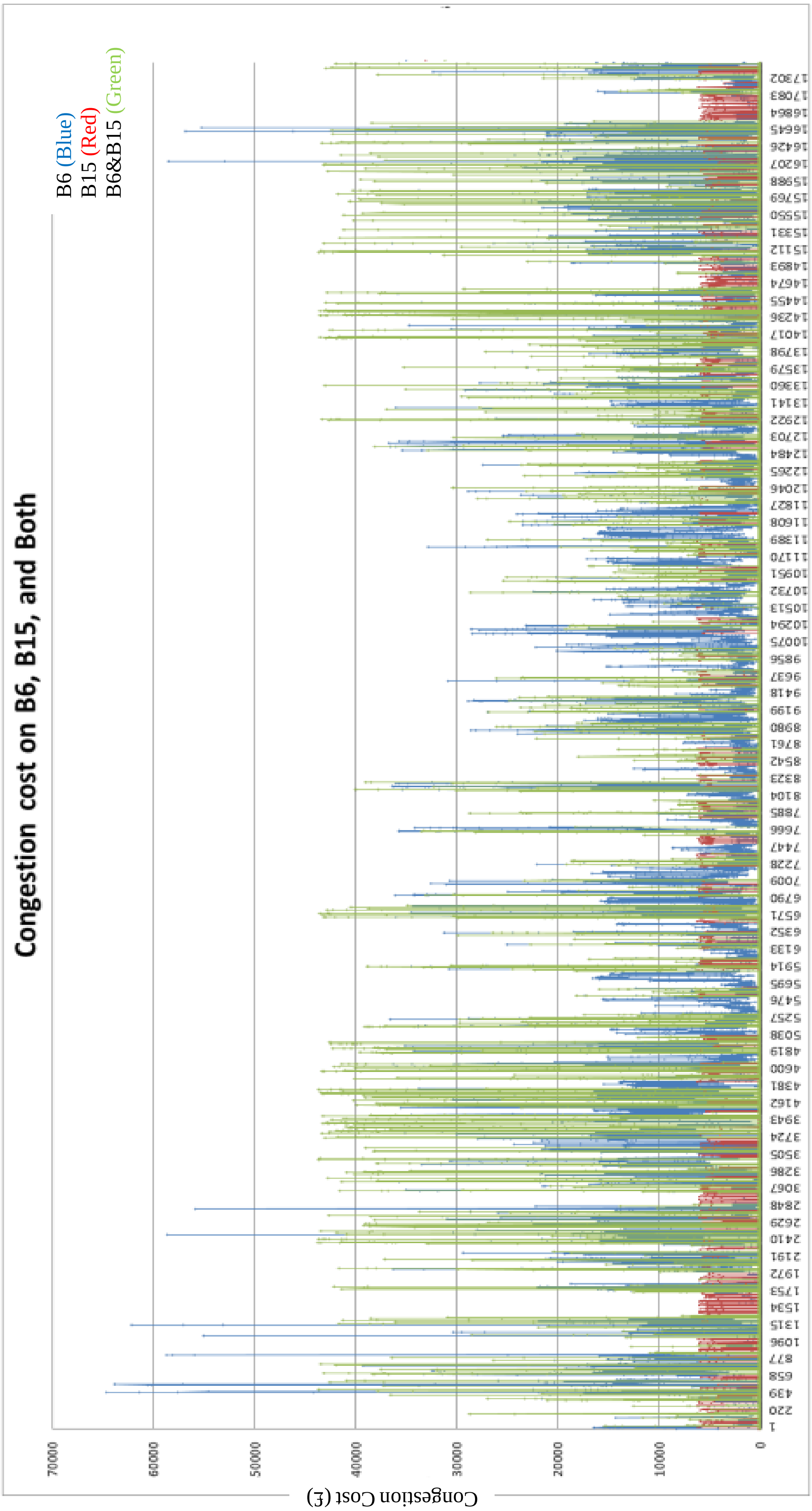

Figure 3-6 Congestion Costs for 17520 Settlement Periods

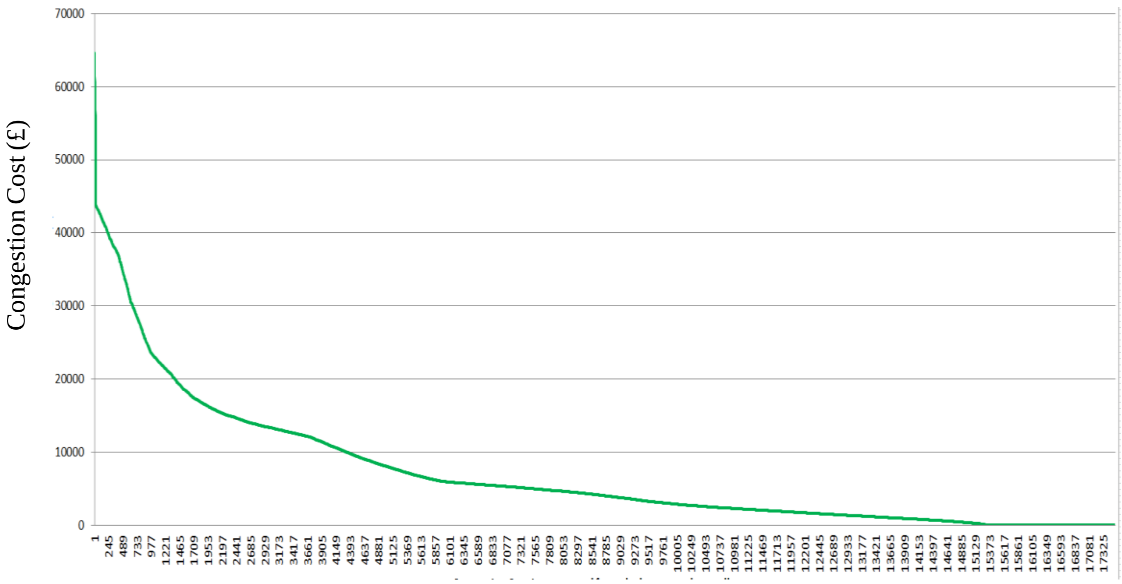

Figure 3-7 Congestion Cost Duration Cure

In Figure 3-7, the adjacent points along the duration curve imply similar congestion costs, thus representing similar degrees of transmission congestions. It is apparent that extremely severe transmission congestions, expressed by high congestion costs, only occur for a very small duration in a year. After those severe transmission congestions, congestion cost declines exponentially to zero.

3.3.3.3. Spatial Distribution of Transmission Congestions

The congestion cost duration curve in Figure 3-7 is further divided into five segments, basing on the different conditions of transmission congestions, as shown in Figure 3-8 (different segments are separated by yellow dashed lines). However, the boundaries between these segments are not absolute. For example, some periods in segment 3 have the same congestion conditions as those in segments 2 and 4.

For each settlement period, a colour code is used to distinguish the congestion cost allocated to B6 (blue) and the congestion cost allocated to B15 (red).

The major feature for each segment is (congestion costs ranges come from simulation results):

- Segment 1 represents the extremely severe congestion from B6 individually. The range of congestion cost in a settlement period is from £75000 to £44000.

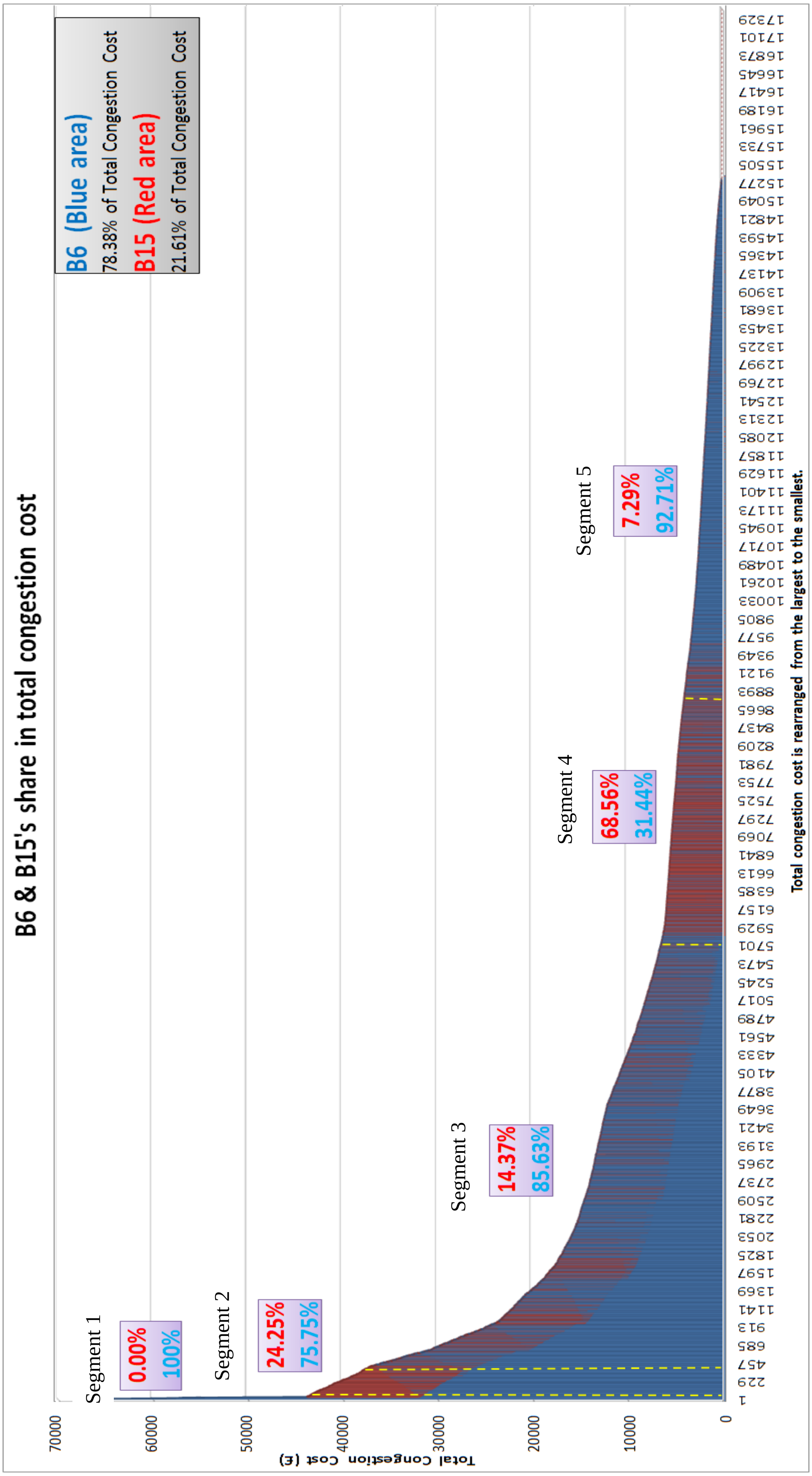

Figure 3-8 Share of B6 and B15 in Congestion Cost

- Segment 2 encompasses most of the severe congestion when both boundaries are congested and some severe congestion from B6 individually. The range of congestion cost in a settlement period is from £44000 to £36000.
- Segment 3 includes the medium congestion from B6 individually, and some congestion when both boundaries are congested. The range of congestion cost in a settlement period is from £36000 to £4000.
- Segment 4 includes mainly the congestion from B15 individually, and some congestion from B6 individually. The range of congestion cost in a settlement period is from £4000 to £3000.
- Segment 5 represents most of the slight congestion from B6 individually, from £3000 to £0 in a settlement period.
- Beyond segment 5, there is no congestion for about 12% of the year. (Thus, the system is congested near 88% in a year.)

Table 3-6 gives the spatial distribution of congestion cost between B6 and B15, which are determined from the areas under different segments of the congestion cost duration curve. The third column and fifth column of Table 3-6 give the contribution to segment congestion cost from B6 and B15. Overall, B6 incurs 78.38%, and B15 incurs 21.62%. In segments 1, 2, 3, and 5, B6 contributes to the majority of transmission congestions. However in segment 4, the position is reversed with B15 accounting for 68.56% of the total congestion cost whilst B6 accounts for only 34.44%.

Table 3-6 Share of Congestion Cost between B6 and B15

Segment	***B6 Congestion Cost (£M)***	***Proportion of B6 in Total CC***	***B15 Congestion Cost (£M)***	***Proportion of B15 in Total CC***	***Total Congestion Cost (£M)***	***Share between Segments***
1	1.3	*100.00%*	0	*0.00%*	1.3	1.06%
2	12.0	*75.75%*	3.8	*24.25%*	15.8	12.87%
3	67.4	*85.63%*	11.3	*14.37%*	78.7	63.91%
4	4.8	*31.44%*	10.7	*68.56%*	15.5	12.57%
5	10.9	*92.71%*	0.9	*7.29%*	11.8	9.58%
Total	96.5	*78.38%*	26.6	*21.62%*	123.1	100%

The total annual congestion cost for the simplified GB power system is £123.1 million, which is reasonable when comparing the reported figure of £70 million in 2007/08 [101]. The seventh column of Table 3-6 gives the contribution to annual congestion costs from different segments. Segment 1 only contributes to 1.06% of annual congestion costs. The contributions of segment 2, 4 and 5 to annual congestion costs are 12.87%, 12.57% and 9.58% respectively. Segment 3 makes the biggest contribution (63.91%).

The different contributions to total congestion cost from different boundaries imply that transmission congestions are not uniform across the transmission system and the degree of upgrading different boundaries are also different. Thus, if the TUoS charges could be location-specific (location for the congested branches, not the connection points of network users), they could better reflect the contribution to the various transmission investments from network users. In this way, transmission charges become more cost-reflective and economically effective in guiding the siting of generation expansion.

3.3.3.4. Temporal Distribution of Transmission Congestions

Figure 3-9 to Figure 3-13 explore the frequency and time of day when congestion is arising from each boundary, or combination of boundaries, for the five segments in the congestion cost duration curve.

These figures are obtained by dividing the settlement periods under each segment to 24 hours in a day. The horizontal axis is the timeline in 0.5 hour intervals. The vertical axis counts the number of settlement periods for this 0.5 hour (please note NOT the congestion cost), thus reflecting the frequency of transmission congestions.

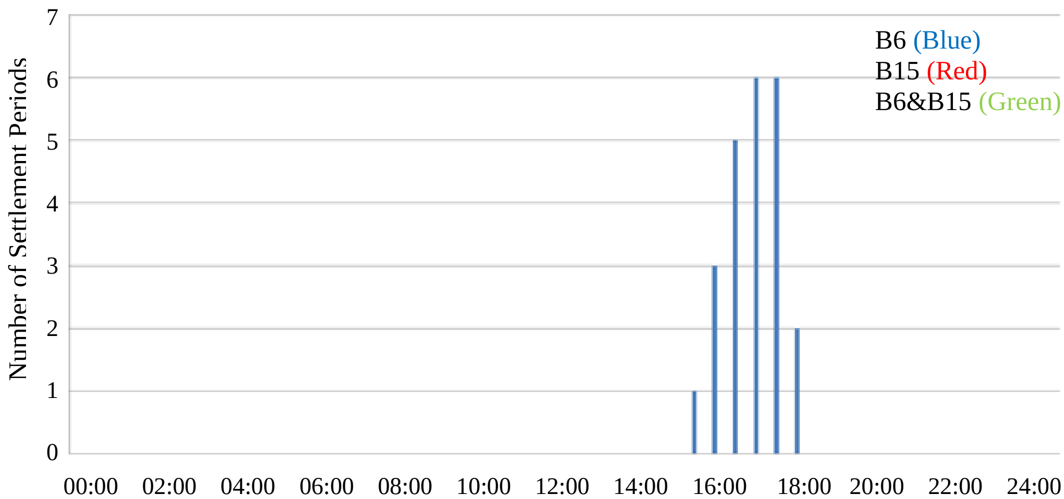

Figure 3-9 Frequency and Time of Congested Settlement Periods in Segment 1

Figure 3-9 demonstrates that exceptionally severe congestions (from B6 individually) are focussed into the six settlement periods around the daily system peak.

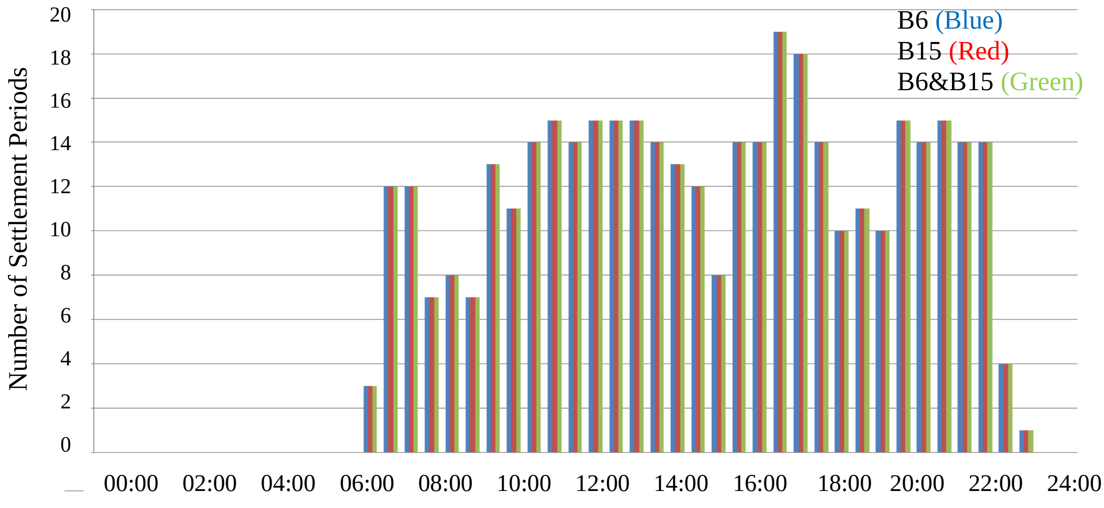

Figure 3-10 Frequency and Time of Congested Settlement Periods in Segment 2

In segment 2, both B6 and B15 are congested or B6 is congested individually. The timing of the congestion becomes more diffuse but still associated with the daytime and evening hours.

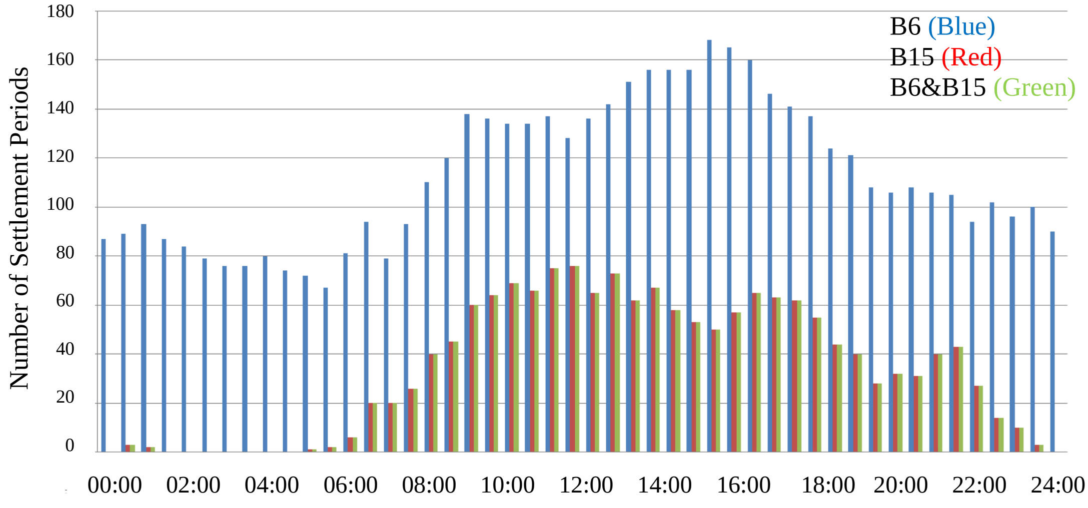

Figure 3-11 Frequency and Time of Congested Settlement Periods in Segment 3

In segment 3, the frequency of congestion on B6 (congested individually for most of time) tends to appear like the typical daily load curve, whereas B15 is only congested during daytime and evening hours as it was in segment 2. When B15 is congested, B6 is normally congested, too. The congestion behaviours of B15 are affected by the assumption about interconnector behaviours, in which interconnectors are assumed to be importing power when demand is from 50% to 80% of system peak.

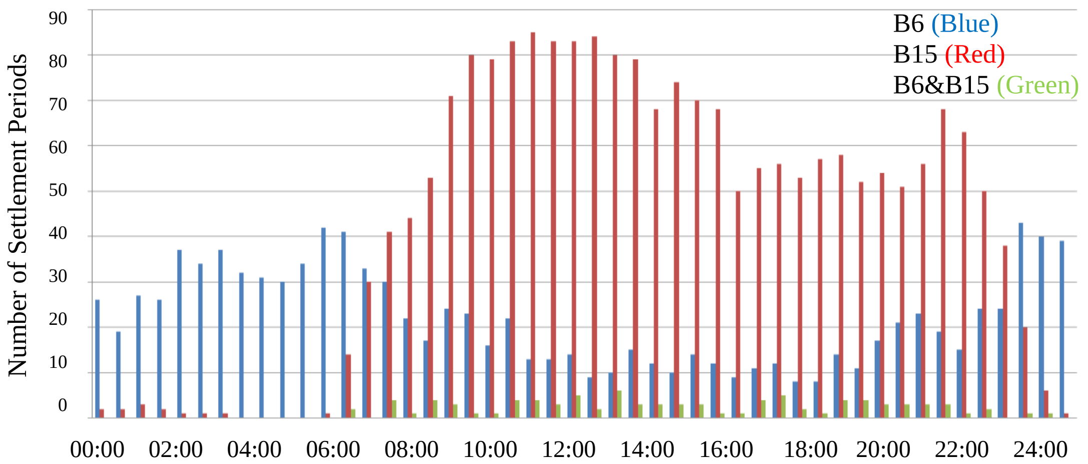

Figure 3-12 Frequency and Time of Congested Settlement Periods in Segment 4

In Figure 3-12, B15 shows the same pattern of congestion as for segment 3 (the same reason as explained for segment 3). However, B6 becomes congested mainly during off-peak hours. The incidence when both of B6 and B15 are simultaneously congested becomes relatively small.

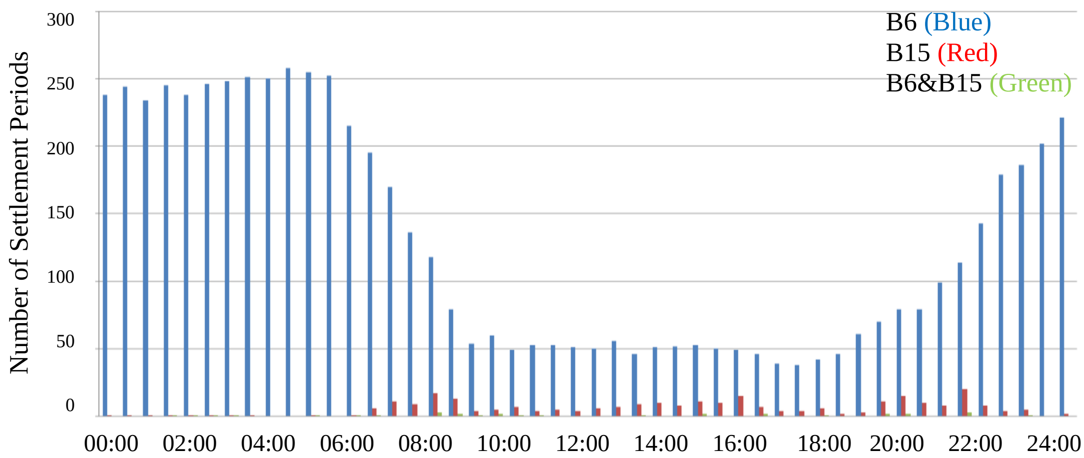

Figure 3-13 Frequency and Time of Congested Settlement Periods in Segment 5

Finally in segment 5, the congestion across B15 falls away. The predominance of congestion across B6 (slightly congested) migrates to the off-peak periods.

Generalising the above analysis, the different degrees of transmission congestions happen in different times of the day, but in relatively fixed hours. Taking B6 for example,

- its severe congestion mainly occurs around the daily system peaks (Figure 3-9);

- its medium congestion tends to appear like the typical daily demand curve (Figure 3-10, Figure 3-12 and Figure 3-11).

- its slight congestion occurs mainly during the off-peak hours (Figure 3-13).

Different degrees of transmission congestions indicate the various levels of required transmission investments. Therefore, if the transmission charges are designed to be time-specific, it could better reflect the contribution to different levels of transmission investments from network users in different times. In this way, the transmission charges become more cost-reflective and is able to provide economic incentivizes to network users for adjusting their behaviours.

This section only shows the temporal distribution of transmission congestions in daily dimension. The analysis about the temporal distribution of transmission congestions across B6 in seasons, months, and different days in a week are given in Appendix A-4. Similar conclusions as above can be summarized from these analysis.

3.3.4 Key Findings

The analysis in this study clearly illustrates that year-round transmission congestions are not uniform across the system but vary largely in magnitude, time and boundary location.

This study develops a congestion cost duration curve, in which the adjacent points represent similar conditions of transmission congestions. This duration curve is further divided into five segments, representing conditions of boundary congested individually or simultaneously, severely or slightly. These segments facilitate to analyse the spatial and temporal distribution of transmission congestions.

Under each segment, the contributions to total congestion cost from different boundaries are different. It implies that the degrees of upgrading different boundaries are also different. Therefore, if the transmission charges could reflect the location where transmission congestions occur, it could be more cost-reflective in recognising the contributions to transmission investments in different branches from network users. This would also enhance TUoS charges’ ability in guiding the siting of generation expansion.

The analysis shows that different degrees of transmission congestions, which indicate the various levels of required transmission investments, happen in different times of the day, but in relatively fixed hours. Therefore, if the transmission charges were designed as time-specific, it could better reflect the contribution to different levels of transmission investments from network users in different times. In this way, the transmission charges become more cost-reflective and are able to provide economic incentivizes to network users for adjusting their short-run behaviours.

In summary, a transmission charging method that could derive transmission charges to charge or reward network users in locations and periods in which they either contribute to or relieve congestion would be useful. However, this implies a more complex procedure in TUoS charges calculation and a time-specific feature in TUoS charging, although these are in accord with the principle of cost-reflectivity.

3.4 Chapter Summary

This chapter lays the foundation for this research work. The studies in this chapter:

- identify what factors should be considered in the design of TUoS charging method;
- present in which form TUoS charges should be to reflect the spatial and temporal distribution of transmission congestions.

The study acknowledges that congestion cost is not determined by a single factor, but by various factors from generation, transmission network and demand. As transmission investments under the economic criteria are decided by the comparison between investment costs and congestion costs, transmission investments are also determined by these various factors. By examining the impacts of these factors on congestion cost, the study comes to the conclusion that generation technology (including generators' production costs and availabilities), transmission capacity and demand profiles should be taken into account in the developing of TUoS charging methods for low carbon power systems.

The study also acknowledges that transmission congestions significantly vary in the magnitude, location and time. A congestion cost duration curve is developed, then divided into several segments representing different conditions of transmission congestions. In these conditions, transmission boundaries are congested individually or simultaneously, severely or slightly. Within each segment, there are considerable differences in the share of congestion costs between different boundaries (the spatial distribution of transmission congestions). Therefore, the TUoS charging method to be developed should be able to reflect the locations where transmission congestions occur. By analysing the temporal distribution of transmission congestions, it is apparent that different degrees of transmission congestions (thus different requirements in transmission investments) occur in relatively fixed hours in a day. This implies to introduce a time-specific feature into TUoS charges.

The findings in this chapter inspire the works in Chapter 4-6.

Chapter 4

Differentiating Generation Technologies in Transmission Charging

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THIS chapter proposes a TUoS charging method that recognises the impacts of system operation on transmission investments, and provides generation technology specific TUoS charges.

4.1 Introduction

The large deployment of renewable generation requires transmission capacities to be built in an economic manner [20], i.e. basing on the trade-offs between operational and investment costs. Consequently, transmission charging methods are required to reflect the diversity in generation technologies and the changes in transmission planning.

Unfortunately, the existing ICRP method employed in the UK is designed for a system dominated by conventional generation. It derives transmission charges based on a single scenario of system peak demand, which however only reflects network users' contribution to transmission investments required for system peak [103, 104]. Moreover, generators are charged based on their installed capacities irrespective of generation technologies. In the low carbon transition of the power industry, the existing transmission charging methods cannot provide cost-reflective charges, thus impeding the development of renewable generation. It is urgent to develop appropriate transmission charging methods for the low carbon transition of the power industry [65].

The work in this chapter proposes a novel TUoS charging method that is able to reflect the trade-offs between operational and investment costs for transmission investments under the economic criteria. The proposed method innovatively recognises the impacts of system operation on transmission investments. It chooses the investment time horizon to reflect the comparison between operational congestion costs and investment costs. It employs a long-run incremental cost (LRIC) approach to identify the impacts from different generation technologies on transmission investments, which are thereafter translated to generation technology specific TUoS charges. The major contribution is to apply the LRIC method to transmission networks by exactly reflect the trade-offs between operational and investment costs.

Among the key drivers for transmission investments identified in section 3.2, the proposed method successfully reflects the impacts of generation technology, transmission capacity and demand profiles. In the key conditions highlighted in section 3.3, the proposed method recognises the various locations of transmission congestions.

An overview of the proposed TUoS charging method is shown in a flowchart (section 4.2). The adopted long-run incremental cost (LRIC) approach and the principles of differentiating generation technologies are carefully explained in section 4.3. Afterwards, the proposed method is demonstrated in a modified IEEE 14 bus power system (section 4.4). Section 4.5 presents the detailed procedure to determine transmission charges under the proposed method. Section 4.6 compares these charges with those under the existing ICRP method adopted by National Grid. And finally, the work presented in this chapter is summarized in section 4.7.

4.2 Flowchart of the Proposed Method

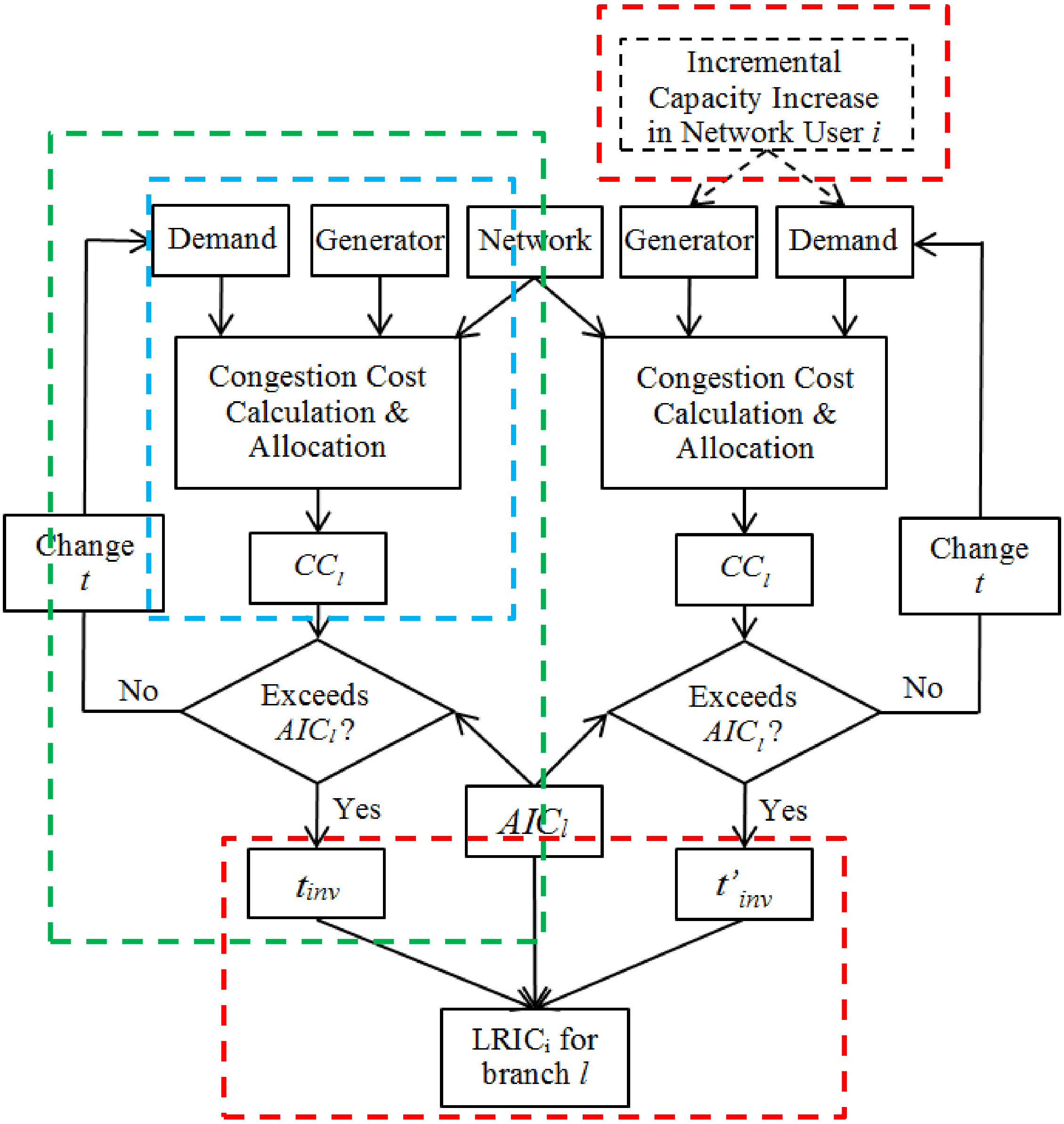


Figure 4-1 Flowchart for the Proposed TUoS Charging Method

Figure 4-1 is the flowchart for the proposed TUoS charging method. It employs a three-stage procedure.

The first stage is to calculate congestion cost and allocate it to congested transmission branches, highlighted by the blue box in Figure 4-1. In the proposed method, the calculation of congestion cost considers various factors from generation, transmission network and demand sectors. And the calculation simulates the network users' behaviours in balancing market. Thereafter, the congestion cost for the whole system is allocated to congested branches, thus facilitating the work in the second stage.

The second stage is to determine the investment time horizon for individual transmission branch, as circled by the green box in Figure 4-1. The primary assumption is that all congested branches are going to be upgraded at a time point in the future (a new parallel power line along the existing one, thus the same investment cost as the existing one). The investment time horizon is determined by increasing the time variable t_{inv}, consequently the demands for year t_{inv} and the annual congestion cost for year t_{inv} will increase. When the annual operational congestion cost allocated to a specific branch is equal to or larger than its annualized investment cost (Definition of annualized investment cost is given in Appendix A-2), the corresponding t_{inv} is the investment time horizon for this transmission branch.

The third stage is to derive TUoS charges through a long-run incremental cost (LRIC) approach, as pointed out by the red box in Figure 4-1. Firstly, an incremental capacity increase is added to a particular network user. This leads to new investment time horizons t'_{inv} for congested transmission branches. The difference in t_{inv} and t'_{inv} is the incremental impact on investment time horizon from this network user. Afterwards, these impacts are translated to TUoS charges, which are the difference between the present values of future investment for congested transmission branches (Definition of present value is given in Appendix A-2). The total TUoS charge for a network user is the sum of TUoS charges for all congested branches.

4.3 Principles of the Proposed Method

4.3.1 Congestion Cost Allocation

4.3.1.1. Congestion Cost

The calculation of congestion cost in the proposed method is more complex than that in Chapter 3. It simulates the behaviours of network users in balancing market, which handles transmission congestions in a commercial manner for the UK transmission networks [105]. Congestion management in balancing market also leads to generation re-dispatches, in which generators are required to increase or decrease their outputs and responsive demands are also involved.

In the balancing market, generators/demand are required to submit their bid/offer prices to the transmission system operator (TSO) [105]. The offer price represents the unit payment from the TSO to generation/demand at which they are willing to increase/decrease their output/consumption. The bid price represents the unit payment to the TSO from generation/demand at which they are willing to decrease/increase their output/consumption.

Figure 4-2 illustrates the bid and offer prices for generators. The horizontal axis stands for generators' output. The vertical axis represents the magnitude of bid/offer prices.

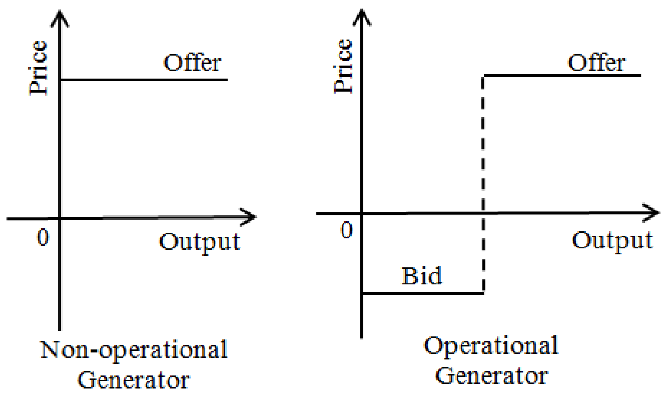


Figure 4-2 Offer and Bid Prices for Generators

For non-operational generators, there are only offer prices. For operational generators, the intersection point of the dashed line and the horizontal axis stands for generator's output determined through bilateral contracts [106]. If TSO asks a generator to increase its output, this generator will get paid from TSO on the basis of its offer price (positive as shown in Figure 4-2). If TSO asks a generator to decrease its output, this generator will pay TSO on the basis of its bid price (negative as shown in Figure 4-2). Generator's production cost is normally smaller than the magnitude of its offer price but larger than that of its bid price. Therefore, it can earn more profits if asked to increase its output and keep part of its profit from bilateral contracts when asked to decrease its output. In this chapter, generators' bid/offer prices are set to be a ratio of their production costs. These ratios are evaluated from the empirical data of generator behaviours in the balancing market, widely used for market simulation and analysis [107]. In addition, zero elasticity is assumed for demand in this thesis, presuming that they do not involve into the balancing market.

The objective of generation re-dispatches is to eliminate congestion with a minimum adjustment cost, at the same time satisfying generation and transmission constraints. Under the circumstance of balancing market, congestion cost (the minimum adjustment cost) is the difference between the payments to accepted offers and the payments from accepted bids [53].

$$CC = \sum Payment\ to\ offers - \sum Payment\ from\ bids \qquad \text{(Eq. 4-1)}$$

4.3.1.2. Congestion Cost Allocation

The allocation of congestion costs in the proposed method helps to effectively compare the costs due to capacity shortage (congestion costs) and the costs for network upgrades (investment costs). A comparison on the whole system level would incorrectly presume that transmission congestions and investment requirements are uniform across the system. However, the comparison on the branch level is able to reflect the different spatial distribution of congestions across transmission networks, as presented in section 3.3. Furthermore, it is easier to acquire and assess the investment costs for individual transmission branch than that for the whole system.

Extensive research has explored the field of congestion cost allocation [36, 108-113], ranging from uniform allocation method [36] to power transfer distribution factor (PTDF) based sensitivity method [111], from aggregated allocation method [108] to Aumann-Shapley value allocation method [109]. By assuming congestions are evenly distributed across the system, uniform allocation method fails to identify the congested branches.

PTDF based sensitivity method relies on a power flow analysis to allocate congestion costs, thus ignoring the fact that the contribution to power flows are not aligned with the contribution to congestion costs. Basing on the "Gaming Theory", Aumann-Shapley value allocation method is the most comprehensive method but too complex for effective allocation. By employing the first step (impose significant influence on the final results) in gaming theory, the aggregated allocation method compromises to achieve a reasonable balance between accuracy and simplicity.

Therefore, the aggregated allocation method from [108] is employed in the proposed method to allocate congestion costs for the whole system to branch level. Figure 4-3 gives the flowchart for the adopted congestion cost allocation method. The main steps are summarized as:

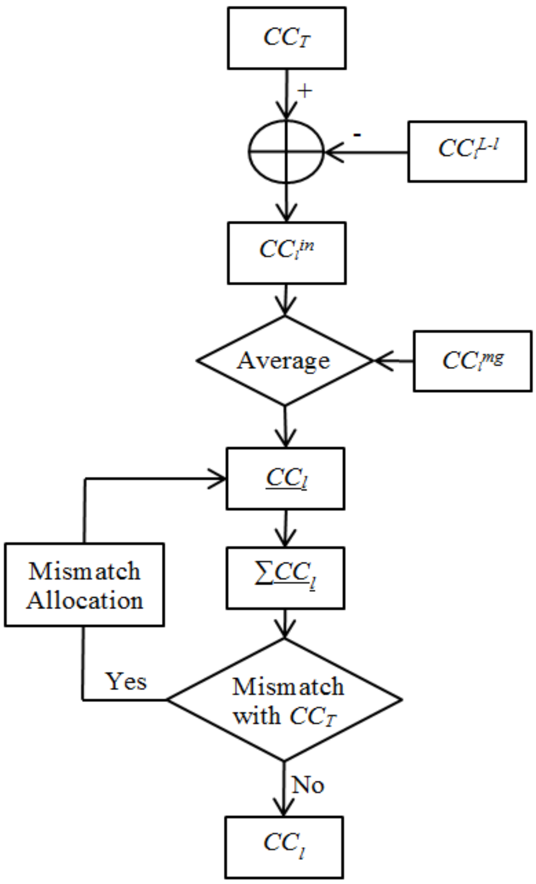


Figure 4-3 Flowchart for Congestion Cost Allocation

1. calculate the total annual congestion cost with all branch capacity limits, CC_T;
2. calculate the annual congestion cost with all branches capacity limits except branch l, CC_l^{L-l};

3. determine the incremental annual congestion cost for branch *l*, CC_l^{in};

$$CC_l^{in} = CCT - CC_l^{L-l} \quad \text{(Eq. 4-2)}$$

4. calculate the marginal annual congestion cost for branch *l*, CC_l^{mg}, which only considers branch *l*'s capacity limit;

5. determine the initial congestion cost allocated to branch *l*, $\underline{CC_l}$,

$$\underline{CC_l} = \frac{1}{2} \times (CC_l^{in} + CC_l^{mg}) \quad \text{(Eq. 4-3)}$$

6. finalise the congestion cost allocated to branch *l*, CC_l, by eliminating the mismatch between CC_T and $\sum \underline{CC_l}$.

$$CC_l = \underline{CC_l} + \Delta CC \times \frac{\Delta PF_l}{\sum \Delta PF_l} \quad \text{(Eq. 4-4)}$$

where

$$\Delta CC = CC_T - \sum \underline{CC_l} \quad \text{(Eq. 4-5)}$$

and ΔPF_l is the difference of power flows on branch *l* with and without considering capacity limits.

4.3.2 Reflecting the Trade-offs in Transmission Charging

The proposed method successfully recognises the impacts of system operation on transmisison investemnts, thus refelcting the trade-offs between congestion costs and investemnt costs in transmission investments under the economic criteria. It is assumed that all congested branches will be upgraded in the future (a new parallel power line along the existing one, thus the same investment cost as the existing one). The time horizons for investing congested transmission branches are chosen as the approach to derive TUoS charges.

Figure 4-4 explains the time horizon of investing transmission branches under the economic criteria. The horizontal axis presents the time horizon. The vertical axis presents the congestion cost.

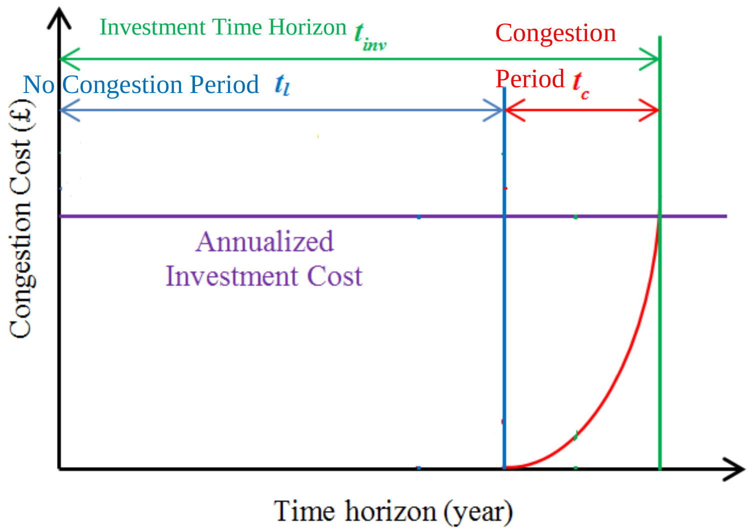


Figure 4-4 Investment Time Horizon

By assming the demand increases every year, the power flow along a transmisison branch increases. Before the power flow exceeds this branch's capacity, transmission congestion does not occur and this situation of no congestion lasts for a period of t_l (the blue line in Figure 4-4). When power flow reaches the capacity limit, congestion occurs. But this branch is not upgraded until the annual congestion cost (*ACC*, the red line in Figure 4-4) allocated to it in a future time exceeds its annualized investment cost (*AIC*, the purple line in Figure 4-4). The situation of congestion management lasts for a period of t_c (the red line in figure 4-4). The time horizon for investing in this branch t_{inv} (the green line in figure 4-4) is

$$t_{inv} = t_l + t_c \qquad \text{(Eq. 4-6)}$$

If an incremental capacity (Δc) is added to one network user (generator or demand), the annual congestion cost allocated to this transmission branch will change, consequently the time horizon to invest in this branch (from t_{inv} to year $t\grave{}_{inv}$).

$$t\grave{}_{inv} = t\grave{}_l + t\grave{}_c \qquad \text{(Eq. 4-7)}$$

The change in investment time horizon due to the incremental capacity (Δc) is presented in Figure 4-5. Solid lines represent the case without the incremental capacity change Δc. Dashed lines represent the case with Δc. t_l, t_c and t_{inv} are plotted in blue, red and green respectively. The purple line stands for annualized investment cost AIC_l, which is compared with annual congestion cost ACC_l (the red curve) to determine t_c, and consequently t_{inv}.

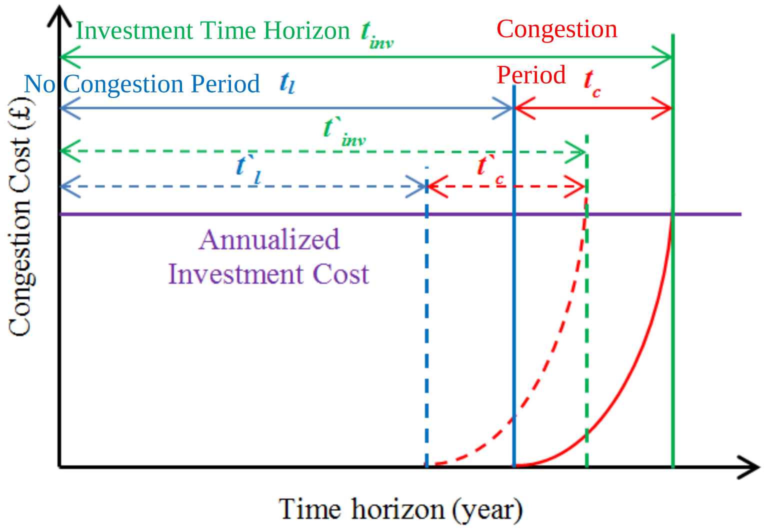


Figure 4-5 Investment Time Horizon after Incremental Increase

It is clear that incremental change from network users can defer or advance the investment time horizons of congested branches. Afterwards, the proposed method employs a long-run incremental cost (LRIC) method to translate the changes in investment time horizons to TUoS charges.

Given the fixed discount rate d, the present value (Definition of the present value is given in Appendix A-2.) for the annualized investment cost for line l in year t_{inv}, $PAIC_l^{t_{inv}}$ and that in year t'_{inv}, $PAIC`_l^{t_{inv}}$ are

$$PAIC_l^{t_{inv}} = \frac{AIC_l}{(1+d)^{t_{inv}}} \quad \text{(Eq. 4-8)}$$

$$PAIC`_l^{t'_{inv}} = \frac{AIC_l}{(1+d)^{t`_{inv}}} \quad \text{(Eq. 4-9)}$$

The difference in the present values with and without Δc is the long-run incremental cost (LRIC) for transmission branch l due to the incremental change from network user i.

$$\mathrm{LRIC}_l(\Delta c) = PAIC`_l^{t'_{inv}} - PAIC_l^{t_{inv}}$$

$$= AIC_l\left(\frac{1}{(1+d)^{t`_{inv}}} - \frac{1}{(1+d)^{t_{inv}}}\right) \quad \text{(Eq. 4-10)}$$

The total TUoS charge for network user i is the summation of all LRIC triggered by its incremental capacity increase.

$$\text{TUoS Charge} = \frac{\sum_l LRIC_l}{\Delta c} \qquad \text{(Eq. 4-11)}$$

4.3.3 Differentiating Generation Technologies

In the proposed method, different generation technologies in the same location can be differentiated. This is because the production costs and availabilities for various generation technologies are set to be different in the calculation of congestion cost. An incremental capacity increase from different generation technologies will impose different impacts on the investment time horizons of congested transmission branches. And consequently, these different impacts are translated into differentiated TUoS charges for various generation technologies.

The proposed method employs simple principles to differentiate generation technologies in TUoS charging. But when compared with the existing TUoS charging methods, it requires more information to derive TUoS charges. For generation sector, the production costs and availabilities (especially for renewable generation) are required. For network sector, the investment costs for congested branches are required. For demand sector, the year-round demand profile is needed. However, the proposed method has its advantages as it does not need to assume future generation and network expansion, only using information pertaining to existing generation mix, transmission network and demand.

4.4 Demonstration System

The proposed method is demonstrated in a modified IEEE 14-bus system [114], as shown in Figure 4-6.

4.4.1 System Parameters

4.4.1.1. Generation Parameters

To illustrate the effectiveness of the proposed method in differentiating generation technologies, different combinations of generation technologies (conventional and renewable) are considered at Nodes N_1-N_4.

Table 4-1 gives the generation parameters for the demonstration system.

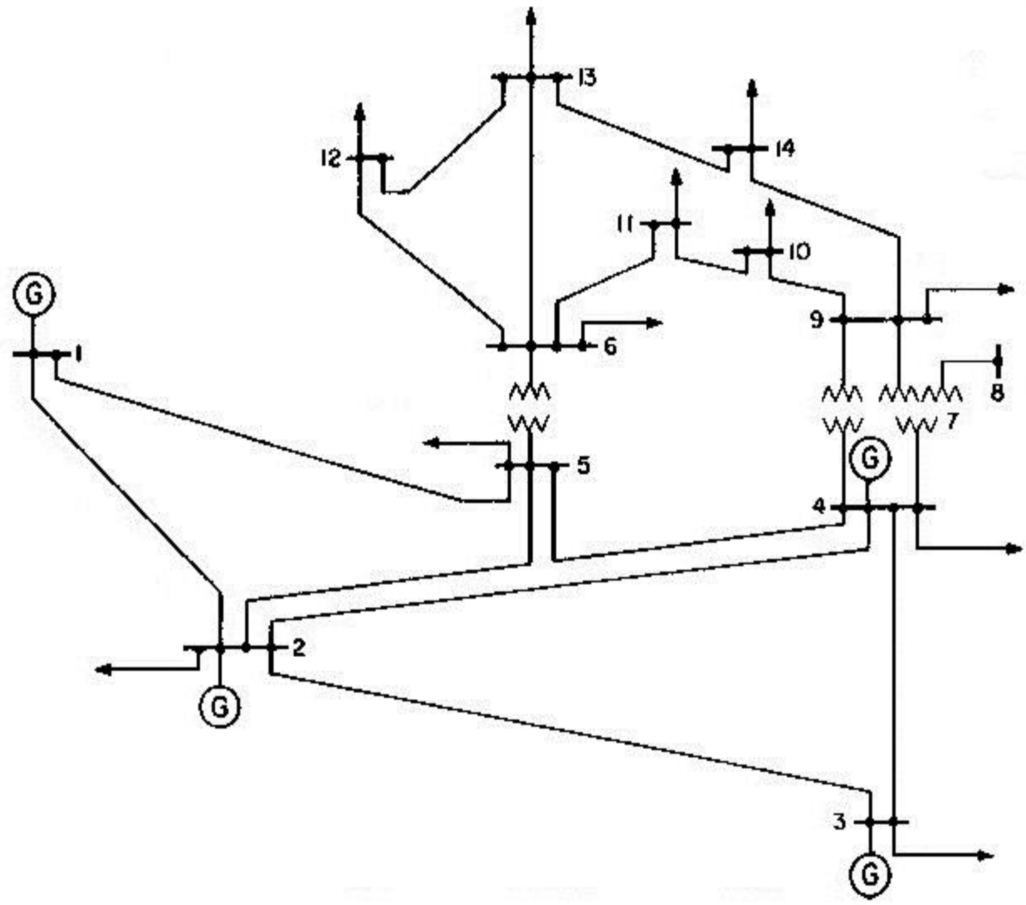


Figure 4-6 Modified IEEE 14 Bus Power System

Table 4-1 Generator Parameters for Modified IEEE 14 Bus Power System

Node	***Generator***	***Technology***	***Capacity (MW)***	***P_{Gi} (£/MWh)***	***Bid ratio to P_{Gi}***	***Offer ratio to P_{Gi}***
N_1	G_1	Nuclear	50	6.5	-	-
	G_2	Coal	100	35.73	-0.6	1.6
	G_3	Wind	30	0.1	500	-
N_2	G_4	Coal	50	39.99	-0.6	1.6
	G_5	Gas	50	45.23	-0.6	1.6
N_3	G_6	Gas	30	47.68	-0.6	1.6
	G_7	Wind	20	0.1	500	-
N_4	G_8	Wind	10	0.1	500	-

The main assumptions about generation sector are:

- Generators' production costs (P_{Gi}) are set to typical values from DECC's report on Electricity Generation Cost [115].

- Generators' bid/offer prices are set to be a ratio of their production costs. These ratios are evaluated from the empirical data of generator behaviours in the balancing market, which are widely used for market simulation and analysis [107]. Nuclear generator G_1 has inflexible generation, therefore it is excluded in congestion management (no bid and offer prices). Conventional generators G_2, G_4-G_6 are assumed to have -0.6 ratio to P_{Gi} for bid prices and 1.6 ratio to P_{Gi} for offer prices. Wind generators G_3, G_7 and G_8 have low P_{Gi} to reflect their priorities in economic dispatch. However, their bid prices are set as 500 thus they are rarely asked to reduce their outputs in congestion management, reflecting that the system would like as much as demand to be met by renewable energy. The ratio of 500 comes from the assumed price for Renewable Obligation Certificate (ROC) (£50/MWh in this research work, referred to [116]). There are no offer prices for wind generators as they cannot independently increase their outputs due to the limits from natural resources.

- Conventional generators are assumed to be available whenever required subject to their installed capacities. Wind generators are assumed to follow the historical 2012 UK wind generation pattern, obtained from BM Reports on National Grid Status [117].

- Total generation capacity is sufficient to meet demand growth for the foreseeable future, thus generation expansion is not necessary before transmission expansion.

4.4.1.2. Transmission Network Parameters

Table 4-2 gives the transmission network parameters for the demonstration system.

The main assumptions about the network are:

- Network impedances are available from [114].

- Transmission losses and outages are not considered.

- Branch investment costs are assumed based on a reasonable unit investment cost (£17.013/MW/km/year in 2010/11 [53]).

- Branch capacity limits are set based on the outputs from employing the method proposed in [87], which is able to consider the N-1 contingency.

Table 4-2 Network Parameters for Modified IEEE 14 Bus Power System [114]

Branch	***From Bus***	***To Bus***	***Capacity (MW)***	***Investment Cost (£ 10^5)***	***Annualized Investment Cost (£ 10^5)***
B_1	1	2	115	34.4	2.50
B_2	1	5	55	43.9	3.19
B_3	2	3	55	41.1	2.99
B_4	2	4	50	24.9	1.81
B_5	2	5	50	14.9	1.09
B_6	3	4	20	3.98	0.289
B_7	4	5	50	9.97	0.724
B_8	4	7	40	0	0
B_9	4	9	30	0	0
B_{10}	5	6	50	0	0
B_{11}	6	11	15	0.75	0.054
B_{12}	6	12	15	1.20	0.087
B_{13}	6	13	25	2.49	0.181
B_{14}	7	8	20	0.20	0.015
B_{15}	7	9	40	0	0
B_{16}	9	10	15	0.45	0.033
B_{17}	9	14	20	1.60	0.116
B_{18}	10	11	15	0.45	0.033
B_{19}	12	13	15	0.75	0.054
B_{20}	13	14	15	1.20	0.087

4.4.1.3. Demand Parameters

Demand peak for each node is given in Table 4-3.

Table 4-3 Demand Parameters for Modified IEEE 14 Bus Power System [117]

Node	*Load (MW)*	*Node*	*Load (MW)*	*Node*	*Load (MW)*
N_1	0	N_6	11.2	N_{11}	3.5
N_2	21.7	N_7	0	N_{12}	6.1
N_3	94.2	N_8	0	N_{13}	13.5
N_4	47.8	N_9	29.5	N_{14}	14.9
N_5	7.6	N_{10}	9		

The main assumptions about demand are:

- Demands at different nodes are assumed to vary simultaneously, following the historical UK demand pattern in 2012 [117].
- Demands are assumed to increase with a fixed growth rate, which is 0.5% per annum [100].

4.4.2 Simulation Procedure

The calculation of congestion cost employs the economic dispatch function in Matpower package [99]. The proposed method calculates the annual congestion cost via a similar method in Appendix A-3. One simulation for a scenario of demand and wind output includes two cases, one without considering branch capacity limits and one with considering branch capacity limits. The difference of generators' outputs in these two cases represent the quantity of bids/offers accepted by the TSO, which are then multiplied by their bid/offer prices to obtain the congestion costs for the whole system. The allocation of congestion cost is achieved by extending the branch capacity limits in the second case via the adopted congestion cost allocation method.

The determination of investment time horizons and the derivation of TUoS charges are achieved via Matlab programming. An initial value for time variable is firstly assumed.

Then, the congestion cost for this future time is calculated and allocated to the congested branches. Basing on the difference between the congestion cost for a congested branch and its annualized investment cost, the time variable is increased or decrease proportionally. The above procedure is repeated until the annual congestion cost equals to the annualized investment cost, and the time variable in this simulation is saved as the determined investment time horizon. Afterwards, an incremental capacity increase is added and a new investment time horizon is determined. Finally, TUoS charges are determined as the difference of the present values of branch reinforcement under the two investment horizons.

For the modified IEEE 14-bus power system, it takes about 1 hour to obtain the TUoS charges. The configuration of the desktop employed in this research work is an Intel Core 2 6400@ 2.13GHz CPU and a 4GB memory.

4.5 Results and Discussion

4.5.1 System Operation at Year 0

Generators' load factors at year 0 (no demand growth) are given in Table 4-4. Nuclear generator G_1 has unity load factor. Coal-fired generators G_2 and G_4 are the second cheapest generation after nuclear, therefore they have higher load factor than G_5 and G_6. Although P_{G5} is smaller than P_{G6}, G_6 has higher load factor than G_5 due to network congestion. Wind generators G_3, G_7 and G_8 have the same load factor as they follow the same pattern. Due to the high bid priced (£50/MW), they are not curtailed in congestion management.

Table 4-4 Generator Load Factor at Year 0

	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8
Load Factor	1.0	0.80	0.29	0.22	0.01	0.05	0.29	0.29

At year 0, the power flows on branch B_1- B_5 and B_7 may exceed their capacity limits but the other branches are never congested. Table 4-5 gives the probability of congestion occurring on B_1-B_5 and B_7. These probabilities are obtained by firstly counting the congested settlement periods for each branch, then being divided by the total number of settlement periods in a year.

Table 4-5 Branch Congestion Probability at Year 0

	B_1	B_2	B_3	B_4	B_5	B_7
Probability	2.9%	2.9%	4.1%	1.4%	0.4%	1.6%

At year 0, the demand at each node varies from 35.91% to 100% of its annual peak demand. Demand growth in every year causes the power flows along transmission branches to increase, consequently the congestion costs allocated to different branches.

4.5.2 Annual Congestion Cost

At year 0, annual congestion cost for the whole system is £2.64×10^5. Table 4-6 gives the congestion costs allocated to B_1-B_5 and B_7 (CC_1-CC_5 and CC_7).

Table 4-6 Branch Congestion Cost at Year 0

	B_1	B_2	B_3	B_4	B_5	B_7	***Total***
Congestion Cost (£ 10^5)	0.32	1.05	0.87	0.23	0.001	0.16	2.64

Figure 4-7 gives the CC_1-CC_7 for the next 20 years. The horizontal axis is the time horizon of 20 years. The vertical axis shows the magnitude of congestion cost.

The results show that only CC_2-CC_4 and CC_7 will reach their corresponding annualized investment costs. Therefore, incremental capacity changes from network users will only influence the time horizons to invest in B_2- B_4 and B_7. Thus, transmission charges only come from the changes of present values for investing in B_2- B_4 and B_7.

4.5.3 Investment Time Horizon

Without capacity changes from any network user, the investment time horizons for B_2-B_4 and B_7 are 15.62, 19.90, 21.56 and 15.78 years respectively. On this basis, the changes of investment time horizon for B_2- B_4 and B_7 due to incremental capacity change from each generator are given in Table 4-7. (Results for demand are given in Appendix A-5.)

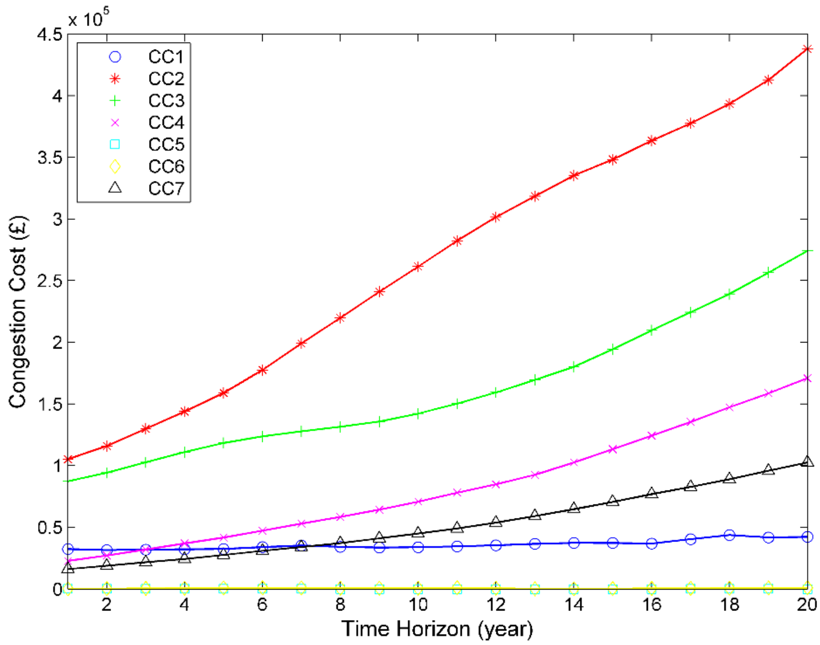


Figure 4-7 Congestion Costs for B_1- B_7 over next 20 years

Table 4-7 Investment Time Change for B_2- B_4 and B_7

Incremental Capacity Change from	***Investment Time change for B_2 (year)***	***Investment Time change for B_3 (year)***	***Investment Time change for B_4 (year)***	***Investment Time change for B_7 (year)***
G_1	-2.33	1.75	0	-1.57
G_2	-2.15	1.75	0	-1.57
G_3	-0.73	0.28	0	-0.24
G_4	0.52	-0.21	-0.41	-0.24
G_5	0.04	0.13	-0.05	-0.24
G_6	-0.44	0.13	-0.05	-0.24
G_7	0.24	1.26	0.34	0.54
G_8	0.98	0.40	0.65	1.06

In Table 4-7, a positive investment time change means deferred network investment whilst a negative investment time change means advanced network investment. Furthermore, if the absolute value of the changes is larger, it means that the expansion from this generator can defer the investment further or advance the investment earlier.

4.5.4 TUoS Charges

Figure 4-8 depicts the TUoS charges for G_1-G_3 at Node N_1, from B_2, B_3, B_4, and B_7. (Exact values are given in Appendix A-5.) Incremental capacity increases from G_1-G_3 advance the investment time horizons of B_2 and B_7, thus they face positive TUoS charges. Incremental capacity increases from G_1-G_3 defer the investment time horizon of B_3, thus they face negative TUoS charges. Incremental increases from G_1-G_3 have no influence on the investment time horizon of B_4, thus their TUoS charges from B_4 are zero.

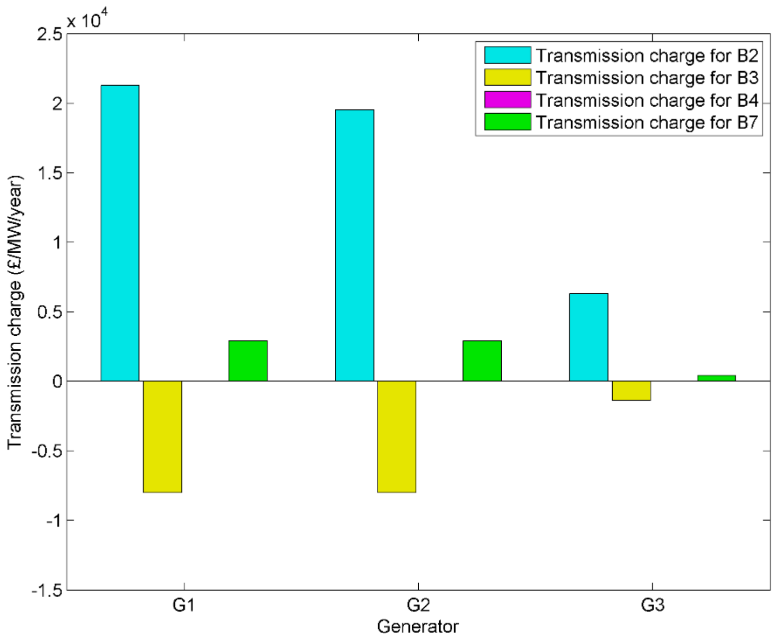


Figure 4-8 TUoS Charges for Generators at Node 1

Moreover, G_1 (-2.33 years from Table 4-7, meaning to advance the network reinforcement by 2.33 years) advances the upgrade of B_2 earlier than G_2 (-2.15 years from Table 4-7, meaning to advance the network reinforcement by 2.15 years). Therefore, G_1 is exposed to larger TUoS charges than G_2. The same philosophy applies when generators defer network investments.

(TUoS charges for other generators and demands are given in Appendix A-5. The same philosophy applies.)

Figure 4-9 and Figure 4-10 show the total TUoS charges for generation and demand respectively. Exact values are given in Appendix A-5. These charges reflect individual network user's influence on the whole system.

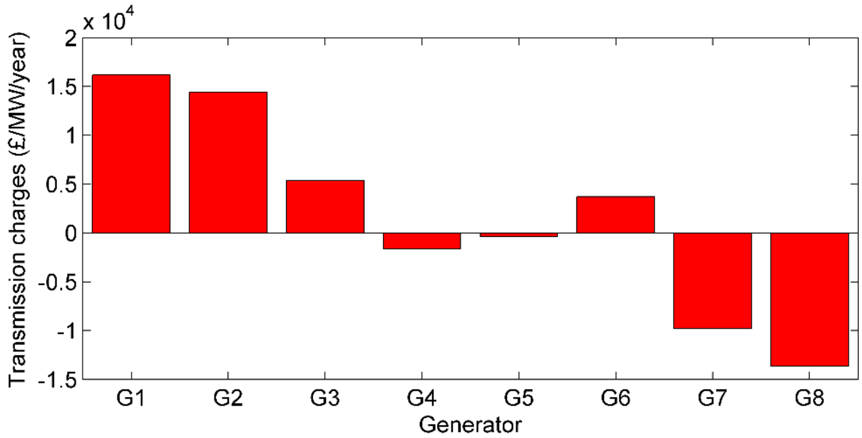


Figure 4-9 Total TUoS Charges for Generation

At Node N_1, wind generation G_3 faces less than one third TUoS charges (£6315/MW/year) compared to the conventional generators connected at the same location (£21281/MW/year for nuclear power plant G_1 and £19516/MW/year for coal-fired power plant G_2), reflecting the fact that renewable generator contributes less to the annual congestion cost thus requires lower or later transmission investments.G_4 and G_5 connected at Node N_2 have negative charges. Conventional generation G_6 connected at Node N_3 pays positive TUoS charge, while wind generation G_7 at the same location sees negative TUoS charge. Wind generation G_8 sees a larger incentive. Clearly, the proposed method can differentiate generation technologies in same locations. Under other considerations such as fuel cost and land availability, future generation expansion will be attracted to locations with low positive TUoS charges (meaning low payment for their use of transmission networks) or negative TUoS charges (meaning to be paid for being connected and available for generation at the connection nodes of transmission networks).

For the same renewable generation technology, G_7 connected at Node N_3 faces different TUoS charges (£6315/MW/year for G_3 which is far from demand and £-8008/MW/year for G_7 which is near to demand), reflecting the fact that generation located far away from demand would require more transmission infrastructure to reach demand.

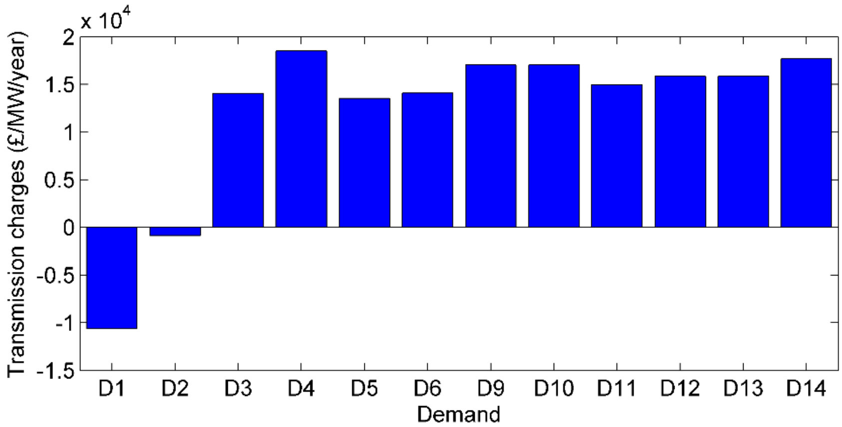


Figure 4-10 Total TUoS Charges for Demand

TUoS charges for demands at Node N_1 and N_3 are negative. Future demand growth will be attracted to these locations, where large cheap generation are connected. TUoS charges for demands at Nodes N_3- N_6, N_9- N_{14} are positive. Future demands at these locations are therefore suppressed.

From Figure 4-9 and Figure 4-10, it can be concluded that the proposed method can provide efficient incentivizes to guide various generation technologies to appropriate locations with reasonable size.

4.6 Comparing with existing ICRP method

The existing Investment Cost Related Pricing (ICRP) method [53] has two main shortcomings.

- It assumes that existing transmission networks are fully utilized and any additional injections will require immediate investment. Therefore, there is no cognition of congestion management, and congestion is not factored into TUoS charges.
- Generation is scaled uniformly to meet system peak demand in the calculation of TUoS charges. This results in the same TUoS charges for generators at the same location, irrespective of generation technologies. The resultant charges become poor in cost-reflectivity, especially in low carbon scenarios, thus causing significant cross-subsidies among different generation technologies.

The proposed method presents remarkable merits to overcome these two defects. A comparison between the existing ICRP method and the proposed method is demonstrated on the modified IEEE 14-bus power system. Only transmission charges gained through economic charging method are compared. (Residual non-locational elements are not considered. Brief introduction about residual elements is in section 2.2.2.2).

Expansion Constant and Local Safety Factor for the ICRP method are chosen as £17.013/MW/km/year and 1.8 respectively [52]. Node N_8 is chosen as the reference node. Branch lengths and Expansion Factors are given in Table 4-8.

Figure 4-11 shows the comparison of TUoS charges between the proposed method and the existing ICRP method.

Table 4-8 Network Parameters for ICRP Method

Branch	B_1	B_2	B_3	B_4	B_5	B_6	B_7	B_8	B_9	B_{10}
Length (Miles)	150	200	250	250	150	100	100	0	0	0
Expansion Factor	1	2	1.5	1	1	1	1	0	0	0
Branch	B_{11}	B_{12}	B_{13}	B_{14}	B_{15}	B_{16}	B_{17}	B_{18}	B_{19}	B_{20}
Length (Miles)	50	50	100	10	0	30	50	30	50	80
Expansion Factor	0.5	0.5	0.5	0.5	0	0.5	0.5	0.5	0.5	0.5

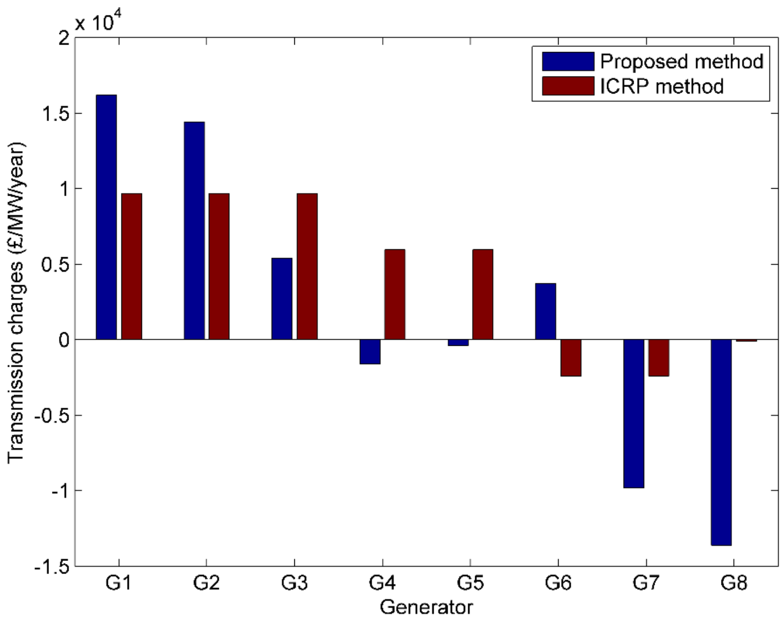


Figure 4-11 Comparing Generation TUoS Charges

It is apparent that the existing ICRP method fails to differentiate generation technologies at the same location. At Node 1, renewable generation G_3 faces the same TUoS charge with conventional generation G_1 and G_2 under existing ICRP method. Under the proposed method, the TUoS charge for G_3 is nearly half of those for G_1 and G_2. Therefore, the existing ICRP method impedes the development of renewable generation at Node 1.

At Node 2, existing ICRP method charges G_4 and G_5, while the proposed method incentives them. The sign of TUoS charge for G_6 also reverses. This is because the existing ICRP method does not incorporate congestion into TUoS charges, leading future generation to inappropriate locations and consequently incurring more serious congestion. Both methods offer negative TUoS charges for G_7 and G_8, but TUoS charges under existing ICRP method are much smaller than those from the proposed method. It means that existing ICRP method provides insufficient incentives for the development of renewable generation at Nodes 3 and 4.

(The comparison of demand TUoS charges between the proposed method and the existing ICRP method are given in Appendix A-5.)

Figure 4-12 and Figure 4-13 compare the TUoS charges for G_3 and G_7 from the existing ICRP method and the proposed method for the next 10 years.

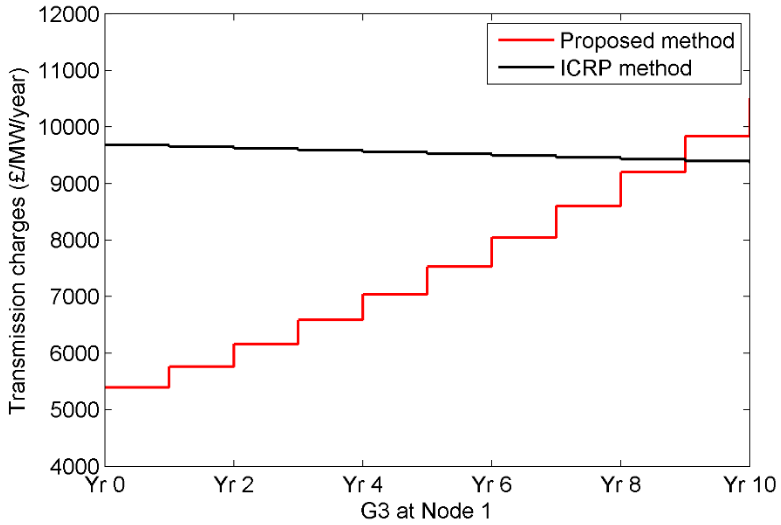


Figure 4-12 Comparing TUoS Charges for G_3 in next 10 Years

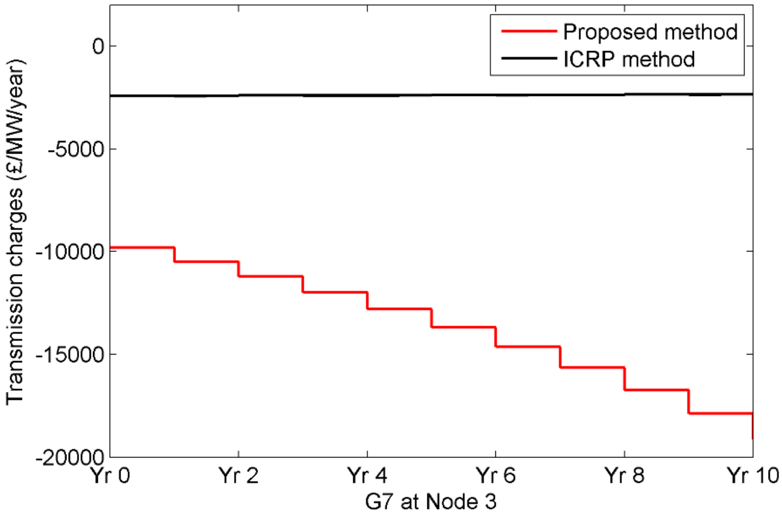


Figure 4-13 Comparing TUoS Charges for G_7 in next 10 Years

For both of G_3 and G_7, it is apparent that TUoS charges under the existing ICRP method remain relatively steady in the long term, but TUoS charges from the proposed method show a continuous adjustment every year (for example, TUoS charges for G_3 increases from £5400/MW/year to £9800/MW/year for the next 10 years), reflecting the extent of system congestions. At Node 1, the increasing TUoS charges might prevent more generation to be deployed hence congestion is not aggravated. At Node 3, the growing incentives will attract more renewable generation and help to defer costly investments.

The efficiency of the proposed method is not only for G_3 and G_7, this is true for all generator and demands.

4.7 Chapter Summary

This chapter proposes an innovative TUoS charging method (called as T-LRIC method hereafter) for low carbon power systems, which is able to:

- recognise the impacts of system operation on transmission investments, thus reflecting the trade-offs between congestion costs and investment costs in transmission investments under the economic criteria;
- differentiate generation technologies by quantifying their various impacts on time horizons of transmission investments.

The proposed method employs a three-stage procedure:

- The first stage is to calculate congestion cost and allocate annual congestion cost for the whole system to branch level. This facilitates the comparison of congestion cost and investment cost on branch level, which exactly reflects the trade-offs in transmission investments under the economic criteria.
- The second stage is to determine the investment time horizon for transmission branches, which is chosen as the approach to derive TUoS charges.
- The third stage is to quantify the impacts of different network users on the investment time horizons, and then translate these impacts to TUoS charges through a long-run incremental cost (LRIC) approach.

The proposed method is demonstrated on a modified IEEE 14 bus power system. The results shows that the proposed method offers positive TUoS charges for network users who contribute to congestion thus advance network investments, and negative TUoS charges for network users who help to eliminate congestion thus defer network investments. Furthermore, the magnitudes of TUoS charges reflect the extent of advancing or differing network investments.

The benefits of introducing the proposed method are highlighted through a comparison with the existing ICRP method. Under the proposed method, different generation technologies at the same locations are differentiated. With changes in demand and generation, TUoS charges from the proposed method continuously adjust every year to reflect the extent of system congestions and the degree of urgency in network investments. These charges will not only provide efficient incentivizes to proactively attract future generation or demand to appropriate locations, thus reducing congestion costs and ultimately investment costs. Critically, they will remove cross-subsidies between renewable and conventional generation. This will in turn enable the efficient development of low carbon power systems.

Chapter 5

Providing Time Specific Signals in Transmission Charging

THIS chapter proposes a novel TUoS charging methods that provide time-specific charges, in which Time-of-Use periods represent typical conditions of system congestions.

5.1 Introduction

The significant difference between renewable generation and conventional generation is the intermittence feature of renewables. Together with the fact that it is not economical to build excess transmission capacities for renewable generation, it becomes unavoidable that transmission congestions occur more frequently, from only during the periods of system peaks to throughout the year whenever renewable resources are abundantly available [118]. TUoS charges, which target to recover investment costs and provide economic signals to network users, are required to become more cost-reflective and economically efficient for the low carbon transition of the power industry.

Advanced transmission charging methods, such as the proposed method in Chapter 4 and other recent developments [78], have tried to reflect the trade-offs between operational and investment costs in transmission investments under the economic criteria. However even so, transmission congestions are simply treated as a whole for one year, leading to fixed annual TUoS charges without distinguishing neither time-of-day nor time-of-year. This chapter proposes a novel TUoS charging method that creatively offers time-specific charges, thus becoming more cost-reflective in distinguishing the various contributions to transmission investments from network users during different times.

Based on the temporal distribution of transmission congestions described in Chapter 3, it is not practical to provide TUoS charges through Critical Peak pricing [119], which only targets extremely high system congestions, or Real-Time pricing [120], which would make TUoS charges varying throughout the year. As a compromise, the proposed method provides time-specific TUoS charges in the form of Time-of-Use, in which the Time-of-Use periods and their corresponding TUoS charges are pre-defined [121, 122]. Time-of-Use periods represent typical conditions of system congestions, consequently different levels of required network investments. If appropriate TUoS charges are given for these periods, network users that are able to change their generation or demand would be encouraged to reduce their network utilization during the periods with high TUoS charges and increase their network utilization during the periods with low TUoS charges. Therefore, this time-specific design could lead to efficient utilization of existing networks.

Among the key drivers for transmission investments identified in section 3.2, the proposed method successfully reflects the impacts of generation technology, transmission capacity and demand profile. In the key conditions highlighted in section 3.3, the proposed method recognises the various locations of transmission congestions and the representative periods when transmission congestions occur.

An overview of the proposed method is shown by the flowchart in section 5.2. The details about the proposed method and the principles of deriving Time-of-Use TUoS charges are carefully explained in section 5.3. A modified IEEE 14 bus power system is employed to demonstrate the proposed method (section 5.4). Section 5.5 presents the procedure to determine TUoS charges. Section 5.6 compares these charges with those in previously proposed methods. And finally, section 5.7 summarizes the work in this chapter.

5.2 Flowchart of the Proposed Method

The proposed method employs a three-stage procedure to derive Time-of-Use TUoS charges. Its framework is given in Figure 5-1.

The first stage aims to obtain the time-series congestion costs (*CC*) and investment costs (*IC*) allocated to each branch, highlighted by the blue box in Figure 5-1. Firstly, time-series congestion costs of the whole system are calculated on the basis of 0.5 hours. Afterwards, time-series congestion costs for the whole system are allocated to congested branches. At last, the annualized investment cost for a congested branch is equally distributed throughout a year based on the magnitude of time-series congestion costs.

The second stage aims to derive time-series TUoS charges, circled by the green box in Figure 5-1. In each settlement period, a long-run incremental cost (LRIC) method is employed. The investment time horizons for congested branches are determined by comparing the increasing congestion costs with the allocated investment costs. And an incremental capacity change from network users will influence these time horizons. Thereafter, the changes in the present values of the allocated investment costs are assigned as the LRIC of congested branches for network users. Times-series TUoS charges for a network user are the sum of LRIC for all congested branches.

The third stage aims to integrate time-series TUoS charges into the form of Time-of-Use, shown as the red box in Figure 5-1. The proposed method firstly classifies one year into eight typical days (four seasons and workday/weekend). Afterwards, it employs hierarchical clustering method to group the time periods in a day into several Time-of-

Use periods, basing on the magnitude of TUoS charges in these time periods. TUoS charges for these Time-of-Use periods are the average values for time periods grouped into corresponding Time-of-Use periods.

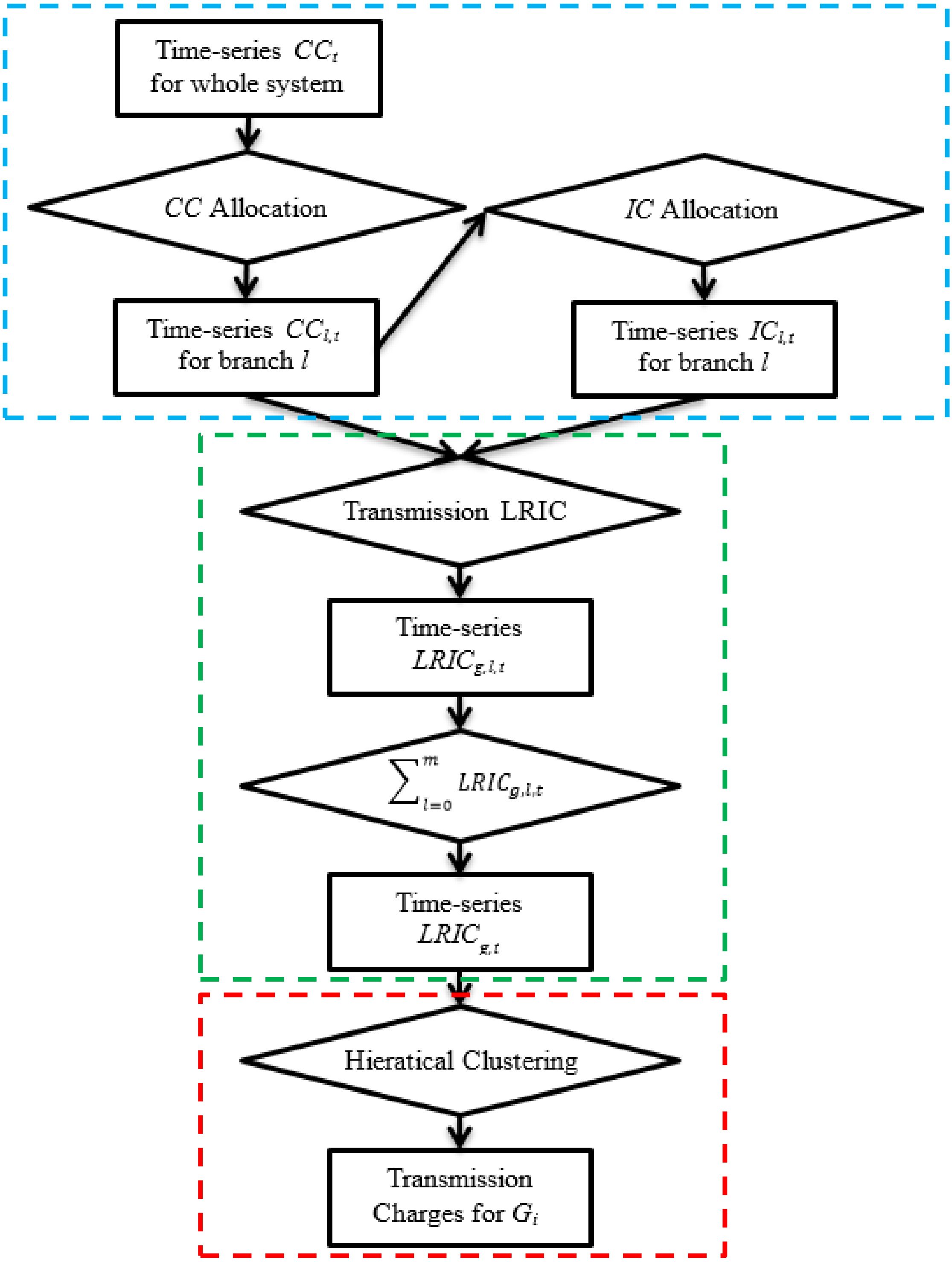


Figure 5-1 Flowchart for the Proposed TUoS Charging Method

5.3 Principles of the Proposed Method

5.3.1 Time-series Congestion Costs and Investment Costs

5.3.1.1. Time-series Congestion Costs

The time-series congestion costs are acquired through simulating the system operation for a year on the basis of 0.5 hours.

The proposed method simulates the behaviours of network users in the balancing market, which handles congestions over the UK transmission networks [105] (detailed introduction in section 4.3.1.1.). Under this circumstance, congestion cost is the difference between the payment to accepted offers and the payment from accepted bids.

$$CC = \sum Payment\ to\ offers - \sum Payment\ from\ bids \quad \text{(Eq. 5-1)}$$

The time-series congestion costs contain the information about the occurrence time of system congestions.

5.3.1.2. Time-series Branch Congestion Cost

The proposed method adopts the aggregated congestion cost allocation method in [108] to allocate congestion cost from the whole system level to branch level (detailed introduction in section 4.3.1.2). These branch congestion costs include the information about the location of system congestions and the corresponding congestion costs.

The main steps of congestion cost allocation are to:

1. calculate $CC_{T,t}$, which is the total congestion cost with all branch capacity limits at time period t;
2. calculate $CC_{l,t}^{L-l}$, which is congestion cost without capacity limit from branch l at time period t;
3. calculate $CC_{l,t}^{in}$, which is the incremental congesiton cost for branch l at time period t;

$$CC_{l,t}^{in} = CC_{T,t} - CC_{l,t}^{L-l} \quad \text{(Eq. 5-2)}$$

4. calculate $CC_{l,t}^{mg}$, which is marginal congestion cost for branch *l* at time period *t*, only considering branch *l*'s capacity limit;
5. calculate $\underline{CC_{l,t}}$, which is the initial congestion cost allocated to branch *l* at time period *t*;

$$\underline{CC_{l,t}} = \frac{1}{2} \times (CC_{l,t}^{in} + CC_{l,t}^{mg}) \quad \text{(Eq. 5-3)}$$

6. obtain $CC_{l,t}$ by eliminating the mismatch $(\Delta CC_{l,t})$ between $CC_{T,t}$ and $\sum \underline{CC_{l,t}}$.

$$CC_{l.t} = \underline{CC_{l,t}} + \Delta CC_{l,t} \times \frac{\Delta PF_{l,t}}{\sum \Delta PF_{l,t}} \quad \text{(Eq. 5-4)}$$

where $\Delta PF_{l,t}$ is the difference of power flows along branch *l* for time period *t*, with and without considering its capacity limit.

5.3.1.3. Investment Cost Distribution

Annualized investment cost for branch *l* is proportionally distributed throughout the year based on the magnitude of time-series congestion costs, thus facilitating the derivation of time-series TUoS charges.

$$IC_{l,t} = AIC_l \times \frac{CC_{l,t}}{\sum CC_{l,t}} \quad \text{(Eq. 5-5)}$$

where $IC_{l,t}$ is the investment cost for branch *l* allocated to time period *t*
AIC_l is the annualized investment cost for branch *l*
$CC_{l,t}$ is the congestion cost for branch *l* allocated to time period *t*

5.3.2 Time-series TUoS Charges

For transmission investments under the economic criteria, transmission networks are reinforced when the annual congestion cost exceeds the annualized investment cost. In Chapter 4, it is assumed that all congested branches will be upgraded at a future time by the way of a new parallel line along the existing one, thus doubling the transmission capacity with the same investment cost.

In this chapter, the proposed method distributes annualized investment costs to time periods along the year. And the comparison becomes between the allocated congestion costs for congested periods and the allocated investment costs. This can reflect the fact that the severity of system congestions vary during different time periods, thus requiring to investing transmission branches in different future times.

A long-run incremental cost (LRIC) method for transmission networks (as explained in section 4.3.2) is employed to derive time-series TUoS charges.

The time horizon of investing transmission branch *l* for time period *t*, $t_{inv,t}$ is determined by comparing the allocated congestion cost and investment cost to find out when $CC_{l,t} \geq IC_{l,t}$.

The present value of the investment cost for branch *l* at year $t_{inv,t}$ for time period *t* is

$$PIC_l^{t_{inv,t}} = \frac{IC_{l,t}}{(1+d)^{t_{inv,t}}} \qquad \text{(Eq. 5-6)}$$

An incremental capacity change (Δc) from a network user (generator or demand) will impact the congestion cost at time period *t*, and consequently the time horizon to invest in the branch (from $t_{inv,t}$ to year $t`_{inv,t}$) for time period *t*.

It also changes the present value from $PIC_l^{t_{inv,t}}$ to $PIC`_l^{t'_{inv,t}}$.

$$PIC`_l^{t'_{inv,t}} = \frac{IC_{l,t}}{(1+d)^{t`_{inv,t}}} \qquad \text{(Eq. 5-7)}$$

The difference in the present values with and without Δc is the long-run incremental cost (LRIC) for branch *l* for this network user at time period *t*.

$$\mathrm{LRIC}_{l,t}(\Delta c) = PIC`_l^{t_{inv,t}} - PIC_l^{t_{inv,t}}$$

$$= IC_l\left(\frac{1}{(1+d)^{t`_{inv,t}}} - \frac{1}{(1+d)^{t_{inv,t}}}\right) \qquad \text{(Eq. 5-8)}$$

The total TUoS charge for this network user at time period *t* is the summation of LRICs from all congested branches.

$$\mathrm{LRIC}_t = \frac{\sum_l LRIC_{l,t}}{\Delta c} \qquad \text{(Eq. 5-9)}$$

In the proposed method, generation technologies are differentiated by examining their corresponding impacts on branch congestion costs and subsequently investment time horizons. These impacts are inherently determined by their production costs and availabilities. (More explanation is given in section 4.3.3).

5.3.3 Time-of-Use TUoS Charges

The proposed method employs a two-step procedure to integrate the time-series TUoS charges into Time-of-Use TUoS charges.

5.3.3.1. Identifying Eight Typical Days

Time-series TUoS charges are firstly grouped on the basis of seasons (spring, summer, autumn and winter) and day types (workday/weekend), resulting in eight typical days. This grouping procedure is aligned with load profiling in [123]. It can reflect the periodic features of demand over seasons and day types and the periodic features of renewable generation over seasons. Table 5-1 gives the definition of seasons in the proposed method (the same definition for load profiles in [123]) and the dates for 2012.

Table 5-1 Definition of Seasons in the Proposed Method

Season	*Definition*	*Dates for 2012*
Spring	Start date of BST* to Summer	26th March 2012 to 12th May 2012
Summer	16 weeks before Autumn Bank Holiday	13th May 2012 to 26th August 2012
Autumn	Autumn Bank Holiday to End date of BST	27th August 2012 to 27th October 2012
Winter	End date of BST to Start date of BST	1st January 2012 to 25th March 2012 28th October 2012 to 31st December 2012

*BST: British Summer Time

The resultant TUoS charges data for a typical day is a d×48 matrix, where d is the number of days for this typical day, 48 is the number of time periods in a day (24/0.5).

5.3.3.2. Determining Time-of-Use TUoS Charges

The determination of Time-of-Use TUoS charges includes the setting of Time-of-Use periods and the values of TUoS charges under these periods.

The two main steps are as follows:

1. determine Time-of-Use periods

Hierarchical clustering method [124] is adopted to determine the shape information for Time-of-Use TUoS charges, i.e. the number of Time-of-Use periods and their time spans.

Without any pre-knowledge about the relationship between data, hierarchical clustering method firstly calculates the distances between the TUoS charges of any two time periods. In this thesis, Euclidean distance [124] is chosen, which is the absolute value of the difference of TUoS charges for two time periods.

$$d_{xy} = \left|TUoS_{tx} - TUoS_{ty}\right| = \sqrt[2]{\left(TUoS_{tx} - TUoS_{ty}\right)^2} \qquad \text{(Eq. 5.10)}$$

where d_x is the distance between time period t_x and t_y, *$TUoS_{tx}$ and $TUOS_s$* are the TUoS charges for time periods t_x and t_y.

Then, two time periods with the smallest distance are grouped together. Afterwards, another time period (“the nearest neighbour”), which has the smallest distance with the minimum time periods in the former group, are grouped in. This procedure are repeated until all 48 time periods are grouped into one group. This procedure of grouping composes a hierarchical tree, as the example given in Figure 5-2. The hierarchical tree shows the result of grouping but not the procedure of grouping. The horizontal axis stands for 48 time periods in a day. The vertical axis stands for the distance between time periods.

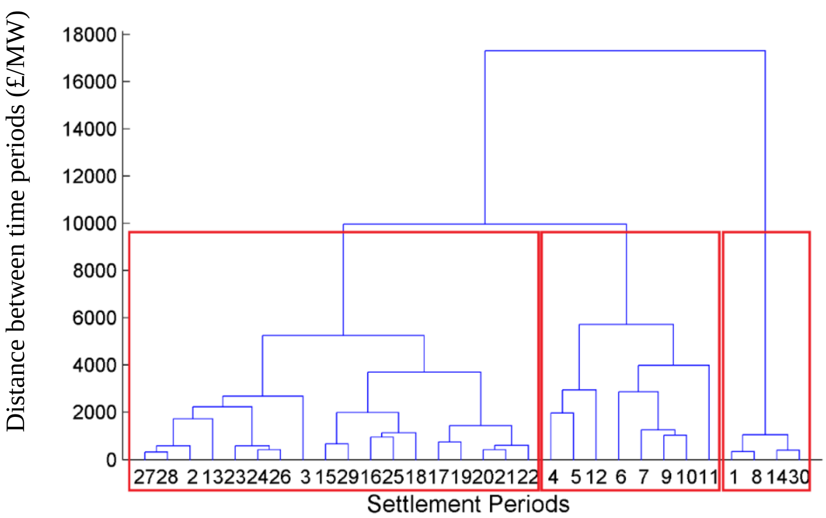


Figure 5-2 Example of a Hierarchical Tree

The proposed method initially classifies three levels of TUoS charges for each typical day: high, medium and low. They are represented by three small groups with lower hierarchy in the hierarchical tree, as shown as the red boxes in Figure 5-2.

Hence, each time period in a typical day is classified into a small group, resulting in that a typical day is divided into several Time-of-Use periods.

2. determine TUoS charges under Time-of-Use periods

The TUoS charge for a Time-of-Use period is the average value of TUoS charges for all time periods grouped into this Time-of-Use period.

However, if the difference between the TUoS charges for different Time-of-Use periods in a typical day is small enough to be ignored, the corresponding Time-of-Use periods are merged together.

5.4 Demonstration System

The proposed method is demonstrated in a modified IEEE 14-bus power system [114], as shown in Figure 5-3.

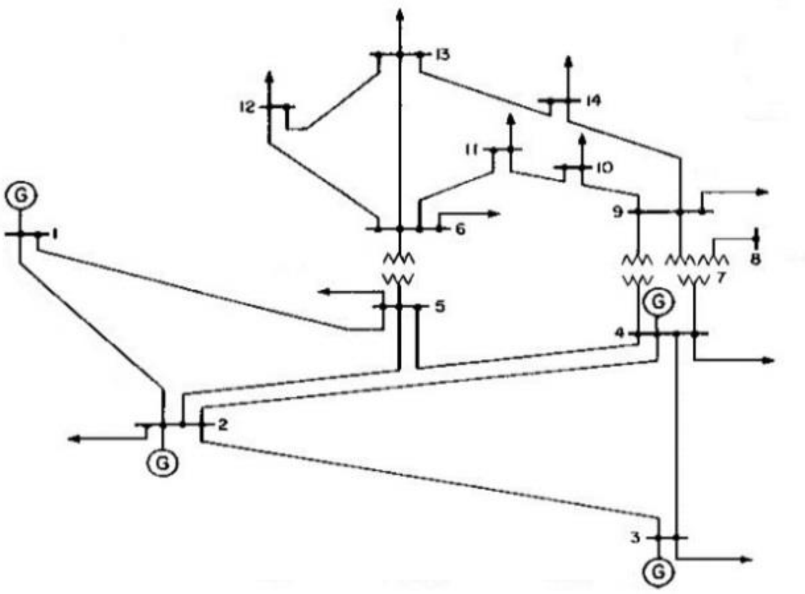


Figure 5-3 Modified IEEE 14 Bus Power System

5.4.1 System Parameters

The parameters for the demonstration system are the same as presented in section 4.4.1.

5.4.2 Simulation Procedure

The calculation and allocation of congestion costs employ the economic dispatch function in Matpower package [99], as explained in section 4.4.2. The other steps of the proposed method are achieved by Matlab programming. The algorithm of Matlab codes in determining investment time horizons and TUoS charges are explained in section 4.4.2. The Matlab codes for determining Time-of-Use periods employ the 'cluster' function in Matlab.

For the modified IEEE 14-bus power system, it takes over 20 hours to obtain the Time-of-Use TUoS charges by employing the proposed method. The configuration of the desktop employed in this research work is an Intel Core 2 6400@ 2.13GHz CPU and a 4GB memory.

5.5 Results and Discussion

The year-round operation of the demonstration system have been presented in section 4.5.1 and 4.5.2. This chapter focuses on the derivation of time-series TUoS charges and Time-of-Use TUoS charges.

5.5.1 Time-series Congestion Costs and Investment Costs

5.5.1.1. Time-series Congestion Cost

Figure 5-4 shows the time-series congestion costs of the whole system on a 0.5h basis for a year. The data are expressed in a three-dimensional coordinate system. One of the horizontal axis represents 24 hours in a day (shown in hours). The other represents 365 days in a year (shown in months). The vertical axis represents the magnitude of congestion cost, rendered by varying colours. Light blue indicates '0' congestion cost, which means no congestion. Blue indicates small congestion costs, which mean slight congestions. Yellow indicates medium congestion costs and red indicates high congestion costs, which mean severe congestions.

In Figure 5-4, it becomes apparent that transmission congestions mainly occur in November, December, January, and February. Moreover, the daily curve of times-series congestion costs shares synchronicities with the daily demand curve, i.e. medium congestions occur during the daytime and severe congestions occur in the early evening.

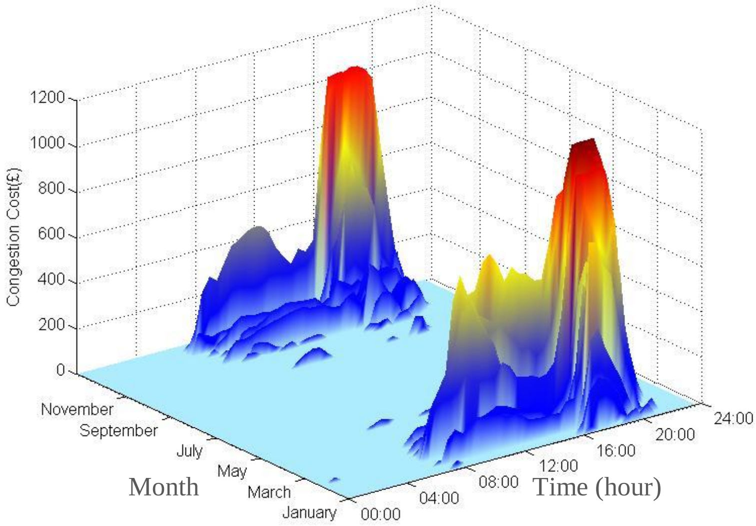


Figure 5-4 Time-series Congestion Costs for the Whole System

5.5.1.2. Time-series Branch Congestion Costs

In the demonstration system, congestions only occur on branch B_1-B_5 and B_7. Figure 5-5 shows the allocated time-series congestion costs for B_1-B_5 and B_7. Data are presented in the same way as in Figure 5-4.

It is apparent that the share of congestion costs among different branches are not the same in the demonstration system.

- Branch 1 seems more likely to be congested in November and December than in January and February.
- Congestion costs allocated to Branch 2 are high. It experiences severer congestions during the daytime of January and February than November and December.
- Congestions on Branch 3 are relatively stable (no extremely severe congestion).
- Congestion costs allocated to Branch 4 are medium, and share a similar curve with the total congestion costs.
- Branch 5 experiences congestions very rarely.

- Congestions on Branch 7 are similar to those on Branch 4, but not that severe.

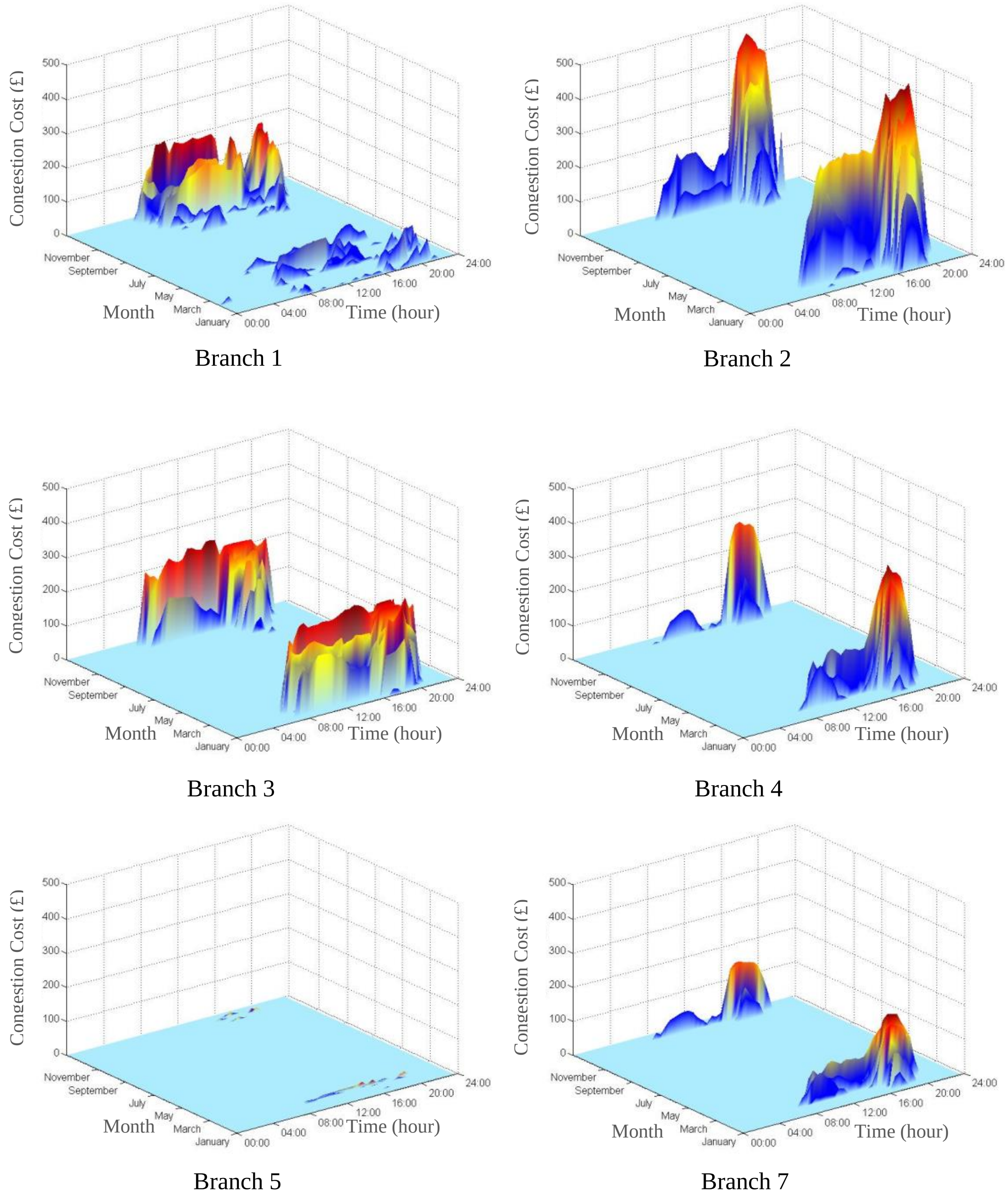


Figure 5-5 Time-series Congestion Costs for Congested Branches

5.5.1.3. Allocation of Branch Annualized Investment Cost

In the proposed method, the annualized investment costs of congested branches are equally distributed to each time periods (0.5h) based on the magnitude of time-series congestion costs. Therefore, the time-series investment costs and time series congestion costs for individual congested branch have the same varying curve.

As the annual congestion costs of congested branches are much smaller than those branches' annualized investment costs (because of this, it takes years before they are upgraded), the allocated congestion cost for each time period are smaller than the allocated investment cost for each time period.

The proposed method employs the investment time horizon for each time period, which is the time required for the allocated congestion cost to exceed allocated investment cost, as the approach to derive TUoS charges.

5.5.2 Time-series TUoS Charges

5.5.2.1. Time-series TUoS Charges for Individual Branches

In the demonstration system, demand growth only causes the congestion costs allocated to branches B_2-B_4 and B_7 to increase. Therefore, TUoS charges only come from network users' impacts on the investment time horizons of B_2-B_4 and B_7. The time-series TUoS charges from branches B_2 and B_3 for all generators are given in Figure 5-6 and Figure 5-7. (The results for B_4 and B_7 are given in Appendix A-6.)

The data of time-series TUoS charges are expressed in a three-dimensional coordinate system. One of the horizontal axis represents 24 hours in a day (shown in hours). The other represents 365 days in a year (shown in months). The vertical axis represents the magnitude of TUoS charges, rendered by varying colours. The time-series TUoS charges for different generators may be positive or negative (stated below each figure), based on their impacts of advancing or deferring the investments of transmission branches (positive for advancing and negative for deferring).

In Figure 5-6 (please note the maximum value of vertical axis is £100/MW per time period), the time-series TUoS charges for generator G_1-G_3 and G_6 are positive, however, those for G_4, G_5, G_7 and G_8 are negative. Conventional generator G_1 and G_2 face large positive TUoS charges, indicating their influences of advancing the upgrade of branch B_2. Renewable generator G_3, connected at the same location, faces also positive but more than halved TUoS charges. Conversely, renewable generator G_8 faces large negative TUoS charges, indicating its influence of deferring the upgrade of branch B_2. It is concluded that the proposed method is effective in differentiating various generation technologies in terms of their influences on transmission investments.

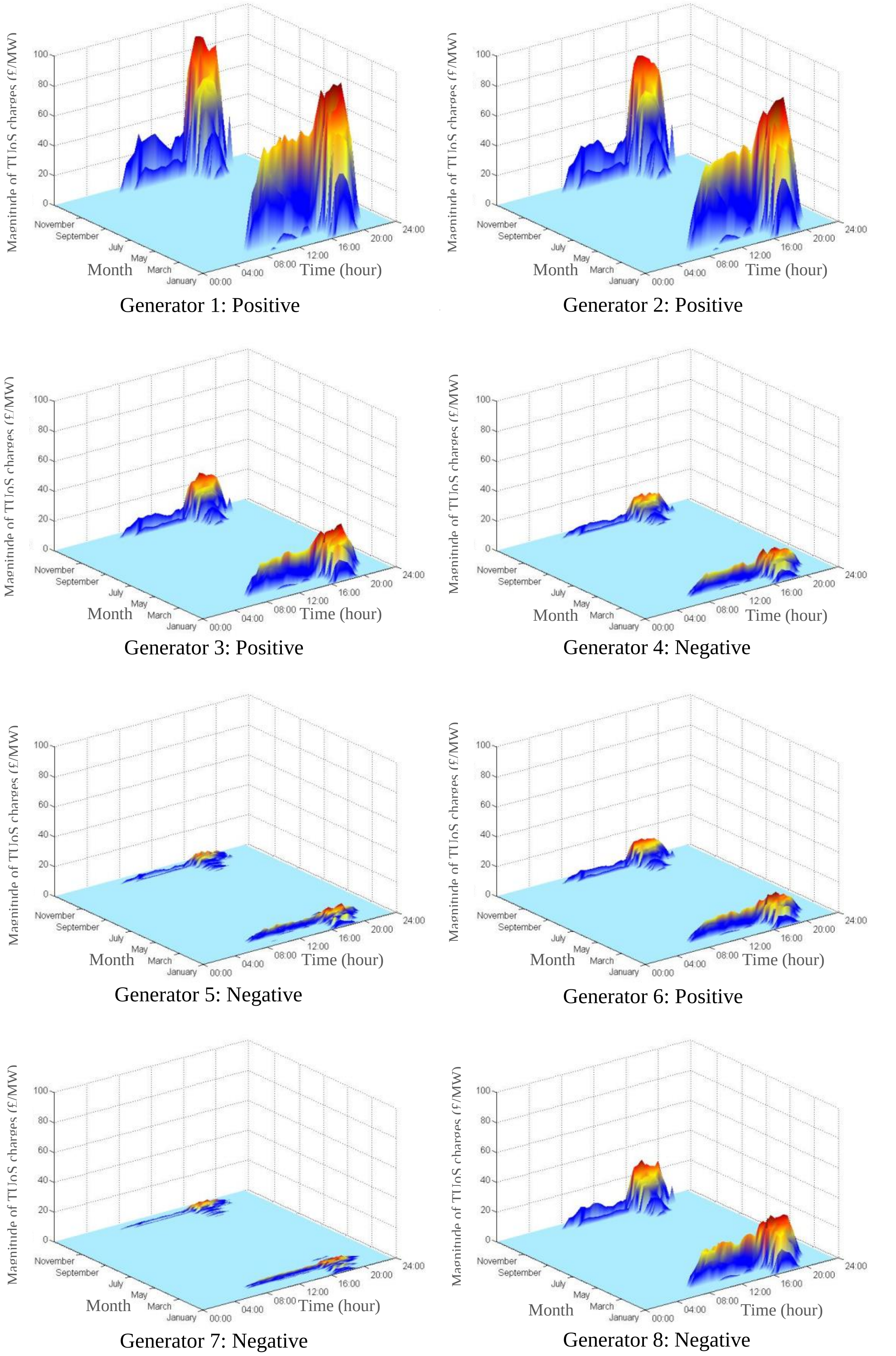


Figure 5-6 Time-series TUoS Charges from B_2 for Generators

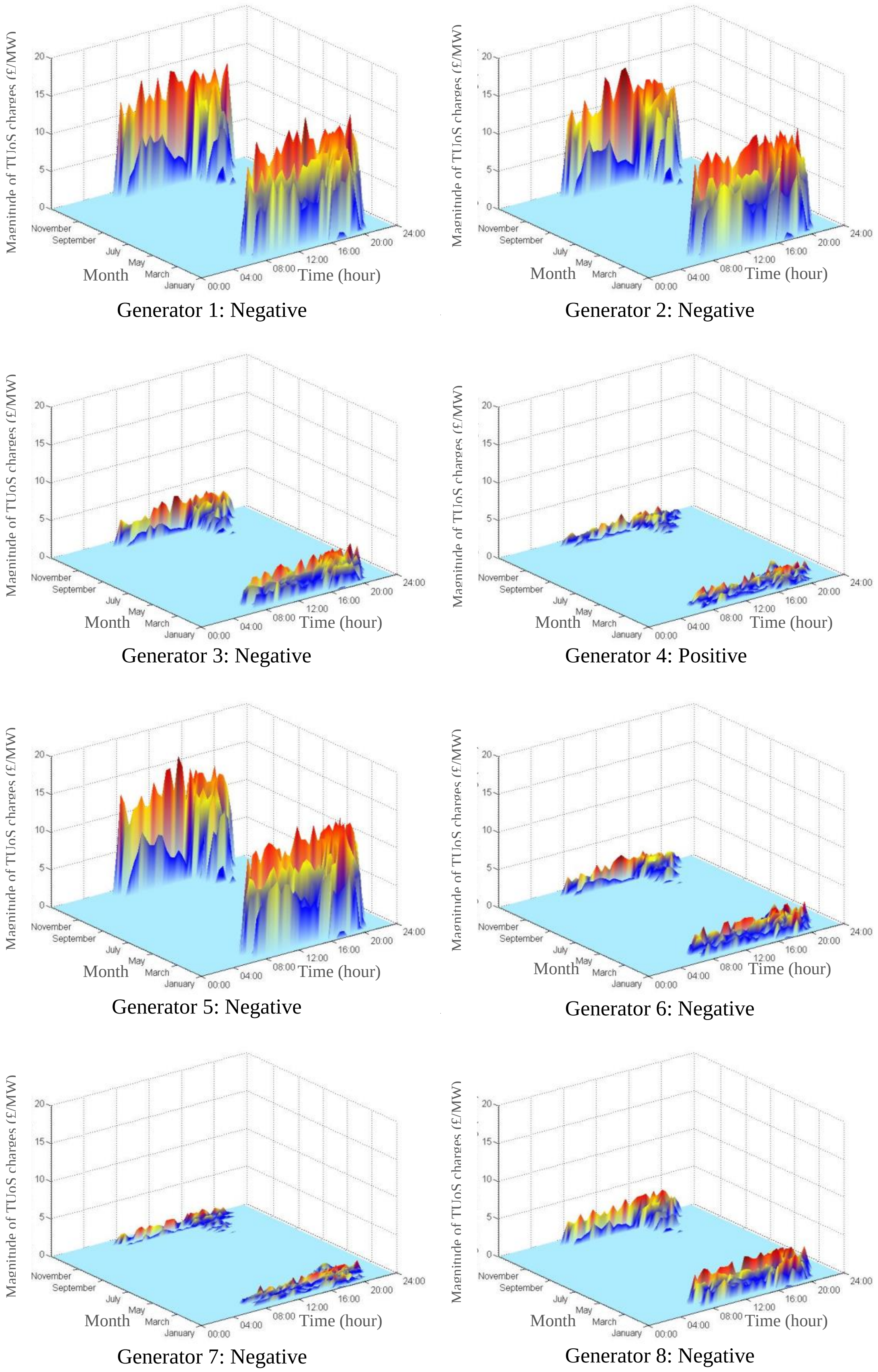


Figure 5-7 Time-series TUoS Charges from B_3 for Generators

In Figure 5-7 (please note the maximum value of vertical axis is £20/MW per time period), the time-series TUoS charges for all generators except G_4 are negative. The same philosophy applied to branch B_2 is applicable to branch B_3. By comparing the influences from network users on different branches, it is apparent that the proposed method is able to identify the spatial distribution of transmission congestions.

(The philosophy in the above analysis is also applicable for the time-series TUoS charges from branch B_4 and B_7, given in Appendix A-6.)

5.5.2.2. Total Time-series Transmission Charges

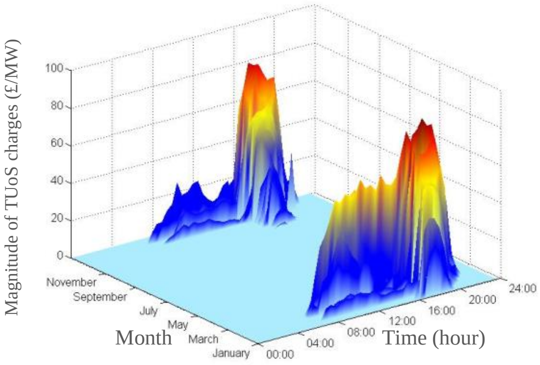
The total time-series TUoS charges for generators are given in Figure 5-8 (please note the maximum value of vertical axis is £100/MW per time period). The total TUoS charges reflect individual network user's influence on the whole system. Generators G_1-G_3 and G_6 face positive TUoS charges, whereas G_4, G_5, G_7 and G_8 face negative TUoS charges.

5.5.3 Time-of-Use TUoS Charges

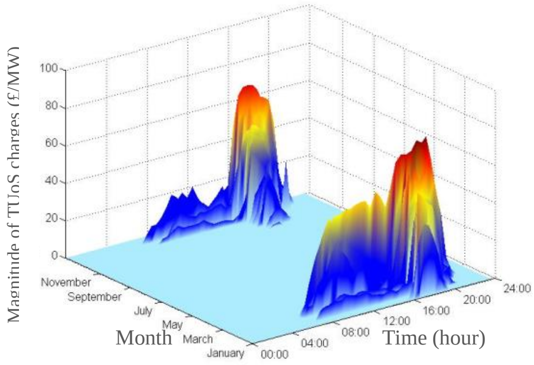
In this proposed method, TUoS charges are only applied to the time periods when congestion occurs. Based on the definition of typical days given in section 5.3.3, majority of congestions in the demonstration system occur in winter (because of the parameters chosen for generation, networks and demand in the demonstration system).

Hence, for the demonstration system, there are only Time-of-Use TUoS charges for winter workdays and weekends. However, this does not mean that the TUoS charges for others times throughout the year would be zero. Transmission charges from economic charging methods (like the proposed methods in this research work) aim to provide economically efficient incentivizes to network users. If the proposed method was applied into practice, the full recovery of allowed revenue would be guaranteed through residual charges (as explained in section 2.2.2.2). As such, TUoS charges for time periods which do not have Time-of-Use charges would be a fixed value for 24 hours of a day, regardless of seasons or day types. However, this is set as future work after this thesis.

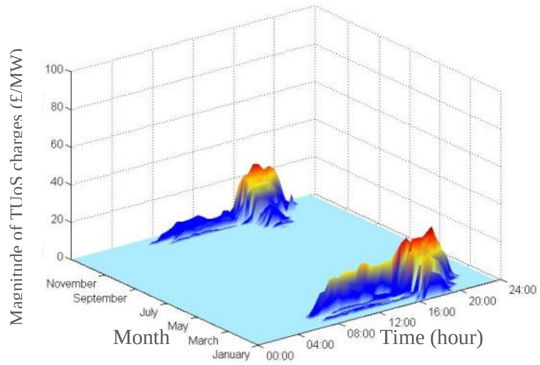
Figure 5-9 and Figure 5-10 give the Time-of-Use TUoS charges for generators for winter workdays and weekends (exact values and time spans are given in Appendix A-6).



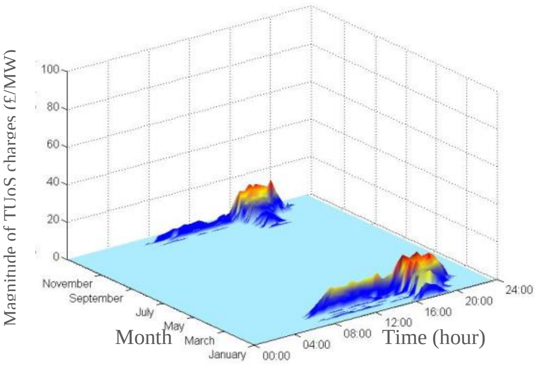
Generator 1: Positive



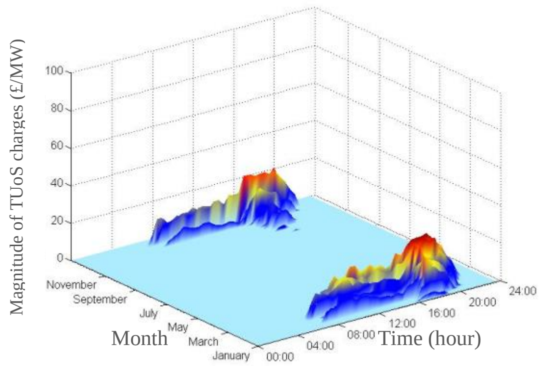
Generator 2: Positive



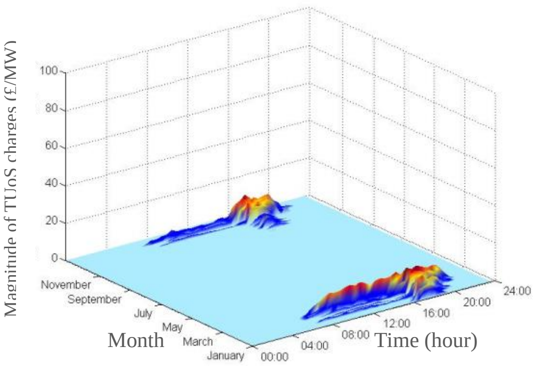
Generator 3: Positive



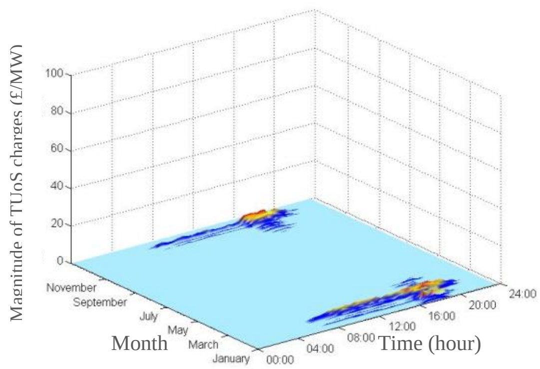
Generator 4: Negative



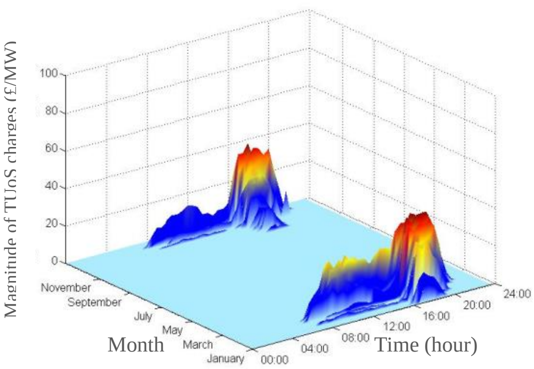
Generator 5: Negative



Generator 6: Positive



Generator 7: Negative



Generator 8: Negative

Figure 5-8 Total Time-series TUoS Charges for Generators

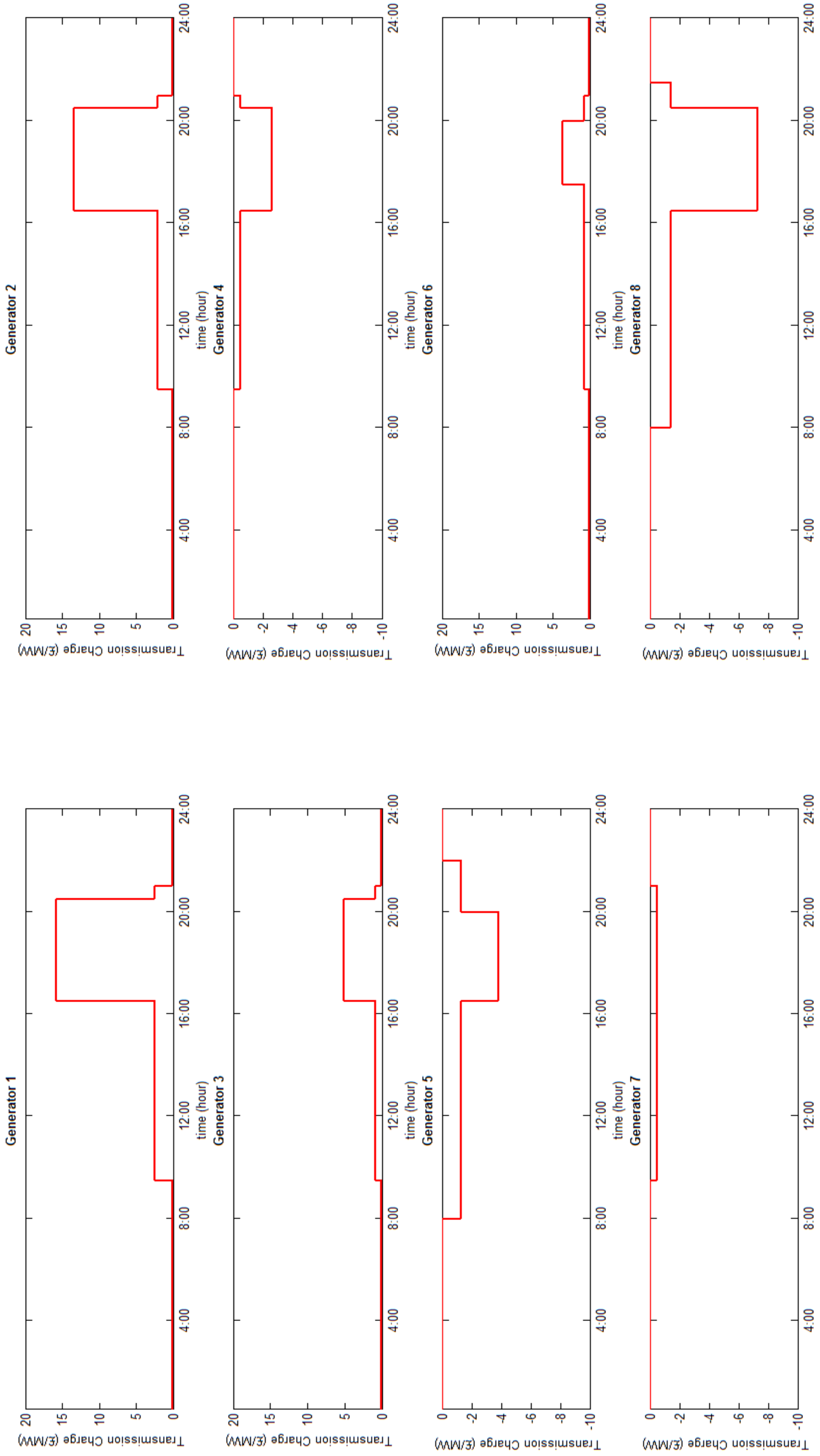


Figure 5-9 Time-of-Use TUoS Charges for Winter Workday

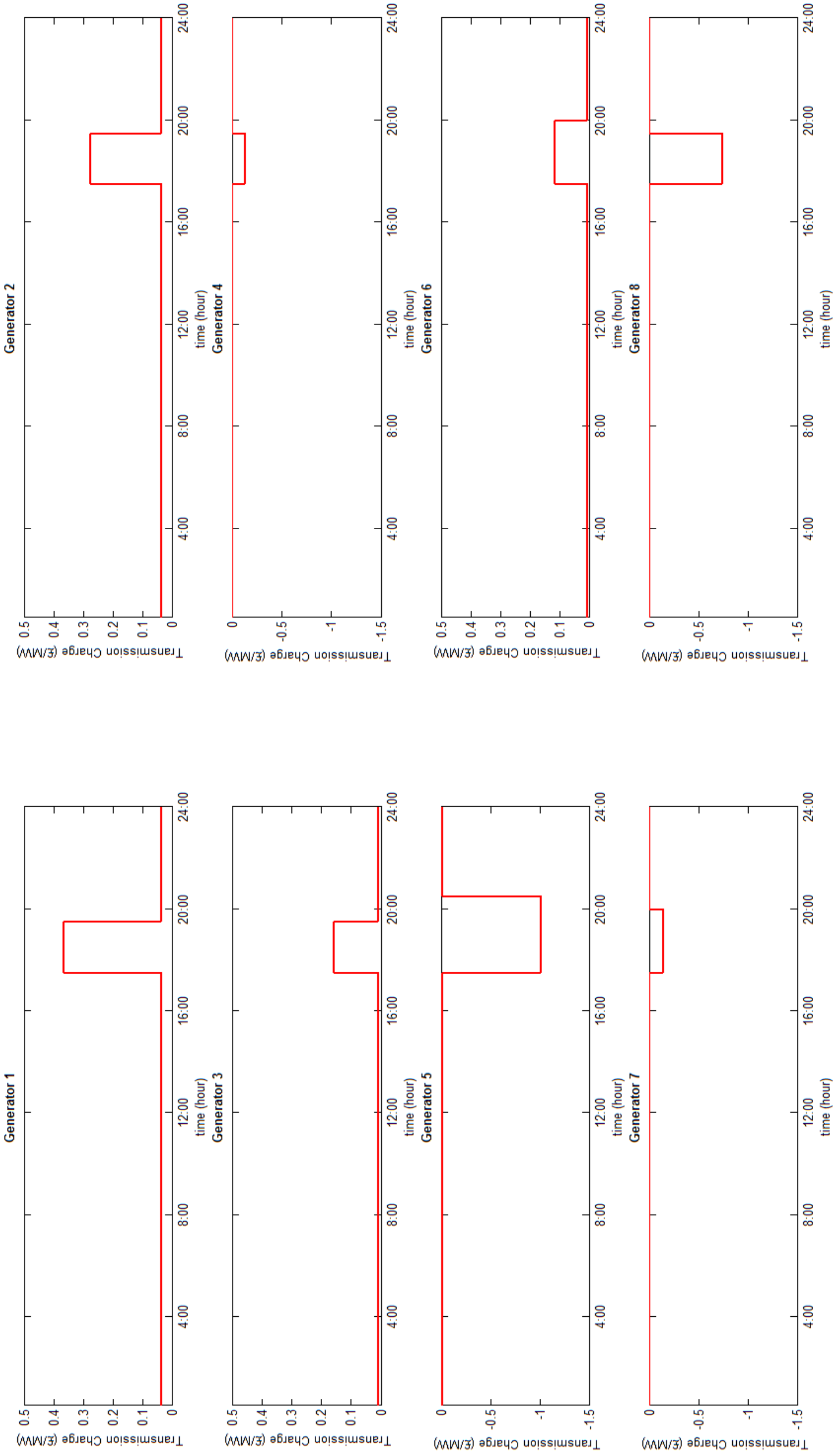


Figure 5-10 Time-of-Use TUoS Charges for Winter Weekend

Generators' Time-of-Use TUoS charges for winter workday consist of three levels of charges (except G_7), resulting in five Time-of-Use periods. The time span of high TUoS charges roughly ranges from 16:30 to 20:30, the time span of medium TUoS charges roughly ranges from 09:00 to 16:30 and from 20:30 to 21:00, and the low TUoS charges periods occupy the rest of the day. The design of Time-of-Use periods under the proposed method successfully reflects the temporal distribution of transmission congestions, thus recognising the various requirements in network investments over different times.

For generators connected at Node N_1, the winter workday TUoS charges for nuclear generator G_1 are £15.80/MW, £2.50/MW and £0.50/MW for high, medium and low congestion period respectively, indicating that high congestions require earlier or larger transmission investments thus ought to face higher TUoS charges. For renewable generator connected at the same location, these figures become £5.11/MW, £0.85/MW and £0.03/MW respectively, indicating renewable generators' low contribution to system investment requirements. It comes to the conclusion that the proposed method can effectively differentiate various generation technologies.

Even for the same technology, renewable generators G_3, G_7 and G_8 face completely different Time-of-Use TUoS charges. The TUoS charges for G_3 are positive, but those for G_7 and G_8 are negative. It is concluded that the proposed method can recognise the connection point of network users, thus differentiate their various contributions to system congestions, and consequently impacts on transmission investments.

Generators' Time-of-Use TUoS charges for winter weekend consist of two levels of TUoS charges, resulting in three Time-of-Use periods. The same philosophy applies.

With the time-specific signals, network users have the pressure to reduce their network using under high positive TUoS charges and the motion to increase their network using under negative TUoS charges. By influencing network users' short-run network utilization behaviours, the proposed method could make an essential contribution to reduce transmission congestions, and ultimately the network investments. Furthermore, as the TUoS charges are generation technology specific, the proposed method can also promote an appropriate generation expansion for low carbon power systems.

5.6 Comparing with Previous Methods

The proposed method in Chapter 5 improves T-LRIC method in reflecting the varying system congestions (thus varying investment requirements) during different times over a year. The proposed method provides TUoS charges in the form of Time-of-Use (ToU). Hereafter, it is called as ToU-LRIC method.

Table 5-2 summarizes the sign of TUoS charges for generators in the existing ICRP method (Chapter 4), T-LRIC method (Chapter 4) and ToU-LRIC method (Chapter 5) ('+' for positive TUoS charge and '-' for negative TUoS charge).

Table 5-2 Sign of TUoS Charges in 3 Methods

Node	***Generator***	***ICRP***	***T-LRIC***	***ToU-LRIC***
N_1	G_1	+	+	+
	G_2	+	+	+
	G_3	+	+	+
N_2	G_4	+	-	-
	G_5	+	-	-
N_3	G_6	-	+	+
	G_7	-	-	-
N_4	G_8	-	-	-

It is apparent that the signs of TUoS charges from T-LRIC method and ToU-LRIC method are consistent. Both methods are able to differentiate generation technologies at the same location. For example, G_6, connected at Node N_3, faces positive TUoS charges, but G_7, connected at the same location, faces negative TUoS charges. Furthermore, both methods reflects the rationale of transmission investments under the economic criteria. They translate network users' impacts on investment time horizons to cost-reflective and forward-looking TUoS charges.

In contrast, the signs of TUoS charges from the existing ICRP method and T-LRIC/ToU-LRIC methods are not consistent. This is because that the existing ICRP method solely relies on power flow analysis, which only reflects the distance that electricity travels to meet demand. Even worse, it provides the same TUoS charges for generators at the same location, irrespective of generation technologies. Existing ICRP method ignores generators' different impacts on system congestions and consequently transmission investments.

5.7 Chapter Summary

The work in this chapter improves the T-LRIC method proposed in Chapter 4 in being able to recognise the temporal distribution of transmission congestions throughout the year. This leads to an innovative Time-of-Use TUoS charging method, which is able to

- recognise the impacts of system operation on transmission investments, and reflect the trade-offs between operational and investment costs in transmission investments under the economic criteria;
- differentiate various generation technologies in TUoS charging, by identifying their different impacts on the time horizons of investing in transmission networks;
- offer time-specific TUoS charges to guide the network users' utilization behaviours in the short-run.

ToU-LRIC method employs a three-stage procedure:

- The first stage aims to obtain the time-series congestion costs and investment costs for congested branches. Time-series investment costs for a congested branch are obtained by proportionally distributing its annualized investment cost based on the magnitude of time-series congestion costs allocated to it.
- The second stage employs a long-run incremental cost (LRIC) approach to derive time-series TUoS charges. TUoS charges for a network user are the sum of its LRICs for all congested branches.
- The third stage integrates the time-series TUoS charges into the form of Time-of-Use. Firstly, eight typical days (four season and workday/weekend) are designed for a year. Then, by employing hierarchical clustering method, several Time-of-Use periods and their corresponding TUoS charges are obtained.

The proposed method is demonstrated on a modified IEEE 14 bus system. The results show that the Time-of-Use periods can represent the typical conditions of system congestions, which then require different levels of transmission investments. The TUoS charges under Time-of-Use periods can provide cost-reflective signals to different generation technologies connected at various locations.

Time-specific TUoS charges can incentivize network users to adjust their network use behaviours of existing networks, thus proactively reducing system congestions throughout the year. The differentiation of generation technologies can guide economically appropriate generation expansion, thus ultimately reducing or deferring future network investments.

An obvious defect of the proposed method is its inefficiency in calculating TUoS charges. Even for the simple IEEE 14-bus power system, it takes over 20 hours to get the results. Most of the time is spent to determine the investment time horizons for hundreds of congested time periods. This inefficiency shows that the proposed method is poor in simplicity and transparency.

Chapter 6

Improving the Existing Investment Cost Related Pricing Method

THIS chapter improves the existing Investment Cost Related Pricing method in terms of differentiating generation technologies and providing time-specific TUoS charges.

6.1 Introduction

The existing Investment Cost Related Pricing (ICRP) method was applied in the UK transmission networks since early 1990s [53], and thereafter, inspired transmission charging designs in many countries [40], such as Brazil and Australia. ICRP method produces annual locational TUoS charges, representing the cost of providing additional transmission capacity to cater for an additional unit of power injection at each node based on a single scenario of system peak [53]. It is qualified for traditional power systems dominated by conventional generation.

In recent years, the power industry is resorting to renewable energy sector for clean and sustainable electricity supply. However, large deployment of renewable generators challenge the existing network charging methods in a variety of ways. Particularly, the output of renewable generation depends on the availability of renewable resources, which are rarely aligned with the varying demand. Thus, renewable generation requires additional network investments at other times rather than system peak. By focusing on a single scenario of system peak, the existing ICRP method fails to

- reflect the investments triggered by network users for different times;
- distinguish renewable generation and conventional generation.

After intense discussion and consultation over the past few years, several modifications have been made to improve its efficiency for the ongoing low carbon transition [78] (detailed introduction is given in section 2.4.2). However, these modifications did not completely eliminate the concerns from network users for reasonable and just TUoS charges (detailed introduction is given in section 2.4.2). In this chapter, a novel Time-of-Use (ToU) TUoS charging method is developed. Its design is based on the principles of ICRP method, but with the following innovative modifications:

- derives time-specific TUoS charges in the form of Time-of-Use charges, whose periods are determined by the year-round congestion costs, thus recognizing the impacts of system operation on network investments over different times throughout a year;

- differentiate various generation technologies by generators' specific load factors under corresponding Time-of-Use periods, thus reflecting their respective contributions to transmission investments over different times;

Among the key drivers for transmission investments identified in section 3.2, the proposed method successfully reflects the impacts of generation technology, transmission capacity and demand profile. In the key conditions highlighted in section 3.3, the proposed method recognises the various locations of transmission congestions and the representative periods when transmission congestions occur.

An overview of the proposed TUoS charging method is shown in a flowchart (section 6.2). The detailed procedure of the proposed method is carefully explained in section 6.3. Afterwards, the proposed method is demonstrated in a modified IEEE 14 bus power system (section 6.4). Section 6.5 presents the demonstration results and discussion under the proposed method. Section 6.6 compares the proposed method in Chapter 6 and previously proposed methods. Finally, the work presented in this chapter is summarized in section 6.7.

6.2 Flowchart of the Proposed Method

The proposed TUoS charging method employs a two-stage procedure, as the flowchart given in Figure 6-1.

The first stage aims to identify the Time-of-Use periods, highlighted by the red box in Figure 6-1. Briefly, the Time-of-Use periods are obtained through clustering time-series congestion costs, aiming to find the representative periods for different levels of system congestions, which indicate different levels of required transmission investments. Time-series congestion costs for the whole system are first allocated to branch level and node level by employing the aggregated congestion cost allocation method [108] and a Power Transfer Distribution Factor (PTDF) based sensitivity congestion cost allocation method. Afterwards, hierarchical clustering method [124] is adopted to group time periods with similar congestion costs in obtaining the number of Time-of-Use periods and their time spans.

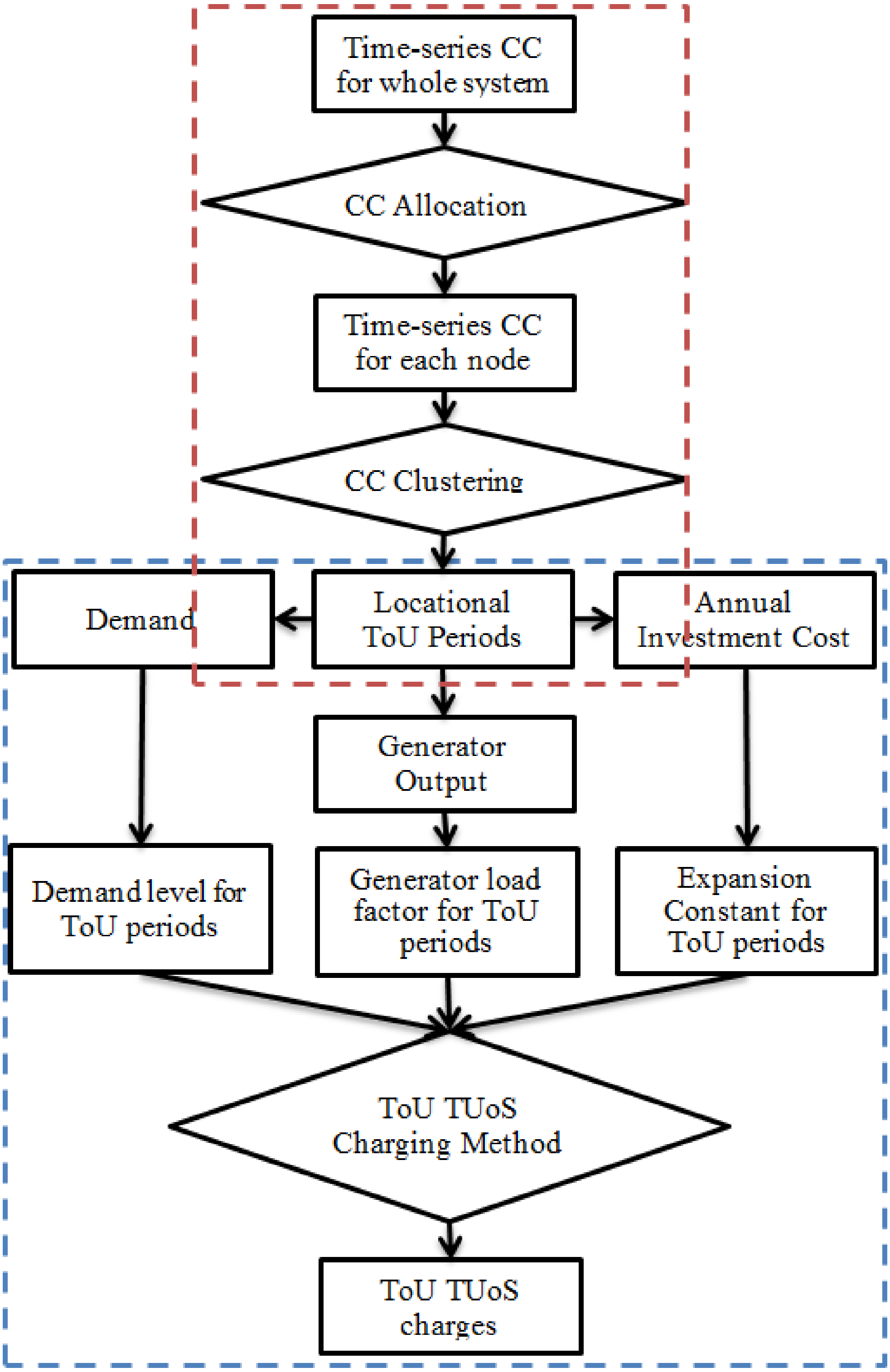


Figure 6-1 Flowchart for the Proposed TUoS Charging Method

The second stage aims to determine the TUoS charges for Time-of-Use periods, as circled by the blue box in Figure 6-1. The proposed method employs the basic principles of ICRP method. However, instead of a single scenario of system peak, the proposed method employs the varying demand levels under Time-of-Use periods thus better reflects the year-round system operation. Besides, specific expansion constants are defined for Time-of-Use periods based on the level of congestion costs, reflecting the investments triggered by different levels of system congestions. Furthermore, in the scaling down generation capacity to demand level, generator capacities are multiplied by generators' specific load factors under corresponding Time-of-Use periods. By quantifying the changes in branch power flows due to a marginal capacity increase from network users, Time-of-Use TUoS charges are determined for different network users.

6.3 Procedure of the Proposed Method

6.3.1 Congestion Cost Calculation

In the proposed TUoS charging method, the impacts of system operation on transmission investments are recognised by exploring the characteristics of congestion costs over different times, in which different levels of transmission investments are required.

First of all, time-series congestion costs are obtained through simulating the system operation for a year. The proposed method simulates the behaviours of network users in the balancing market, which handles congestions over the UK transmission networks [105] (detailed introduction in section 4.3.1.1.). Under this circumstance, congestion cost is the difference between the payment to accepted offers and the payment from accepted bids.

$$CC = \sum Payment\ to\ offers - \sum Payment\ from\ bids \qquad \text{(Eq. 6-1)}$$

The time-series congestion costs contain the information about when system congestions happen.

6.3.2 Congestion Cost Allocation

By recognising that transmission congestions are not even for the whole system, congestion costs for the whole system need to be allocated to branches (detailed explanation in section 5.3.1). Since ICRP method quantifies TUoS charges due to marginal capacity increase from each node, congestion costs need to be further allocated to nodes, thus facilitating the identification of Time-of-Use periods for different nodes.

6.3.2.1. Whole system level to branch level

The proposed method adopts the aggregated congestion cost allocation method in [108] to allocate congestion cost from the whole system to branch level (detailed introduction in section 4.3.1.2).

The main steps are to:

1. calculate $CC_{T,t}$, which is the total congestion cost with all branch capacity limits at time period t;
2. calculate $CC_{l,t}^{L-l}$, which is congestion cost without capacity limit from branch l at time period t;
3. calculate $CC_{l,t}^{in}$, which is the incremental congesiton cost for branch l at time period t;

$$CC_{l,t}^{in} = CC_{T,t} - CC_{l,t}^{L-l} \qquad \text{(Eq. 6-2)}$$

4. calculate $CC_{l,t}^{mg}$, which is marginal congestion cost for branch l at time period t, only considering branch l's capacity limit;
5. calculate $\underline{CC_{l,t}}$, which is the initial congestion cost allocated to branch l at time period t;

$$\underline{CC_{l,t}} = \frac{1}{2} \times (CC_{l,t}^{in} + CC_{l,t}^{mg}) \qquad \text{(Eq. 6-3)}$$

6. obtain $CC_{l,t}$ by eliminating the mismatch ($\Delta CC_{l,t}$) between $CC_{T,t}$ and $\sum \underline{CC_{l,t}}$.

$$CC_{l.t} = \underline{CC_{l,t}} + \Delta CC_{l,t} \times \frac{\Delta PF_{l,t}}{\sum \Delta PF_{l,t}} \qquad \text{(Eq. 6-4)}$$

where $\Delta PF_{l,t}$ is the difference of power flows along branch l for time period t, with and without considering its capacity limit.

6.3.2.2. Branch level to node level

The proposed method employs a Power Transfer Distribution Factor (PTDF) based sensitivity method to allocate congestion cost for branches further down to nodes. The fundamental assumption is that network users' contribution to branch congestion cost are proportional to their contribution to branch power flow.

PTDF describes the contribution to branch power flow from a nodal power injection/extraction [125]. It is defined as the real power change in branch *l* with a unit power injection at node *i* and a unit power extraction in the slack bus. The proposed method inverts its normal application, i.e. targeting to distribute the congestion costs on branches to nodes.

The main steps are to:

1. calculate branch power flow due to nodal injection

$$PF_{li} = (D_i - G_i) \times PTDF_{li} \qquad \text{(Eq. 6-5)}$$

where	PF_{li}	power flow on branch *l* due to node *i*
	D_i	demand connected at node *i*
	G_i	generation connected at node *i*
	$PTDF_{li}$	PTDF for branch *l* due to node *i*

2. calculate power flow contribution factor

$$F_{li} = \frac{PF_{li}}{\sum_{i=1}^{n} \sum PF_{li}} \qquad \text{(Eq. 6-6)}$$

where F_{li} stands for the share of power flow of branch *l* from node *i*, *n* is the total number of nodes.

3. calculate nodal congestion cost

$$NCC_{i,t} = \sum_{l=1}^{m} (CC_{l,t} \times F_{li}) \qquad \text{(Eq. 6-7)}$$

where $NCC_{i,t}$ stands for the congestion cost allocated to node *i* at time period *t, m* is the total number of branches.

6.3.3 Time-of-Use Periods Identification

In the proposed method, nodal congestion costs are grouped to identify the representative periods of system congestions for each node. Therefore, Time-of-use periods are specific for each node, i.e. the same Time-of-Use periods for network users connected at the same location.

The two main steps are to:

1. identify eight typical days

In the proposed method, time-series nodal congestion costs are firstly grouped on the basis of seasons (spring, summer, autumn and winter) and day types (workday/weekend), resulting in eight typical days (detailed introduction is given in section 5.3.3.1.). This grouping procedure is aligned with load profiling in [123]. It can reflect the periodic features of demand over seasons and day types and the periodic features of renewable generation over seasons.

2. identify Time-of-Use periods

The proposed method employs hierarchical clustering method [124] to identify Time-of-Use periods in a typical day. A detailed explanation about hierarchical clustering method is given in section 5.3.3.2.

Similarly, the proposed method classifies three levels of system congestions for each typical day: low, medium and high congestion. This results in a typical day being divided into several Time-of-Use periods. The resultant locational Time-of-Use periods contain only the shape information for TUoS charges, i.e. the number of Time-of-Use periods and their time spans.

6.3.4 Inputs for TUoS Charging

In the proposed method, several inputs for TUoS charging need to be quantified for Time-of-Use periods.

1. ToU period specified demand level

The demand level for specific Time-of-Use period T, $D_{i,T}$, is the average demand for all time periods (0.5h) that are contained in Time-of-Use period T over peak demand.

$$D_{i,T} = \frac{\sum^{t \in T} D_{i,t}}{PD_i \times SP_T} \quad \text{(Eq. 6-8)}$$

where $\sum^{t\in T} D_{i,t}$ stands for the sum of demand at node i for all time periods (0.5h) contained in Time-of-Use period T; PD_i stands for the demand peak at node i; SP_T stands for the number of time periods (0.5h) contained in Time-of-Use period T.

2. ToU period specified generator load factor

The load factor of generator k for specific Time-of-Use period T, $LF_{Gk,T}$, is calculated as

$$LF_{G_k,T} = \frac{\sum^{t\in T} GP_{k,t}}{C_{Gk} \times SP_T} \quad \text{(Eq. 6-9)}$$

where $\sum^{t\in T} GP_{k,t}$ is the sum of outputs of generator k for all time periods (0.5h) contained in Time-of-Use period T; C_{Gk} stands for the capacity of generator k.

3. ToU period specified expansion constant

In ICRP method, Expansion Constant (EC) represents the annualized value of transmission cost to transport 1MW over 1km, quantified as £/MW/km/year [53].

In the proposed method, Time-of-Use period specified Expansion Constants are designed based on the level of congestion costs, thus reflecting the different investments required for different levels of system congestions.

Time-of-Use period specified expansion constant is calculated as

$$EC_{i,T} = \frac{SCC_{i,T}}{SP_T \times \sum SCC_{i,T}} \times EC \quad \text{(Eq. 6-10)}$$

where $SCC_{i,T}$ stands for the nodal congestion costs for node i at all time periods (0.5h) contained in Time-of-Use period T, and $\sum SCC_{i,T}$ stands for the annual nodal congestion costs of node i.

6.3.5 TUoS Charges Determination

The proposed method retains the basic principles of power flow based MW*km and marginal pricing in ICRP method. The major modification is to multiply generator capacities with their specific load factors for Time-of-Use periods (as explained in Section 6.3.4 and are calculated based on the year-round simulation) in scaling generation capacity down to demand. Therefore, this is not uniformly scaling, but distinguishing different generation technologies during different Time-of-Use periods.

The main steps in determining TUoS charges are to:

1. scale generation capacity down to demand

$$\sum^{n} D_{i,T} = \left(\sum^{g} \left(C_{G_k} \times LF_{G_k,T}\right)\right) \times SF \qquad \text{(Eq. 6-11)}$$

   where $\sum^{n} D_{i,T}$ stands for the total demand for Time-of-Use period T, C_{Gk} stands for the capacity of generator k, $LF_{G_k,T}$ stands for generators' specific load factors for Time-of-Use period T, SF stands for the scaling factor to scale generation capacity down to demand.

2. calculate MW*km

   Similar to the existing ICRP method, the proposed method also employs a DC (direct current) power flow model. After executing a DC power flow analysis, there is

$$M = \sum_{l=1}^{m} \left(PF_{l,T} \times L_l \times EF_l\right) \qquad \text{(Eq. 6-12)}$$

   where M stands for the distance (MW*km) that electricity travels over the transmission networks, its dimension is MW*km; $PF_{l,T}$ stands for power flow along branch l in Time-of-Use period T, its dimension is MW, L_l stands for the length of branch l, its dimension is km, EF_l is the Expansion Factor for branch l.

3. add marginal capacity increase

   If a marginal capacity increase is added to a network user, at the same time an additional power extraction/injection at the slack bus, SF in step 1 will change, so does M in step 2. There is

$$\Delta M = M' - M \qquad \text{(Eq. 6-13)}$$

   where ΔM is the change in MW*km due to this marginal increase.

4. determine TUoS charges

   TUoS charge for this network user at Time-of-Use period T is

$$TUoS\ Charge_T = \Delta M \times EC_T \times LSF \qquad \text{(Eq.6-14)}$$

where EC_T stands for expansion constant specified for Time-of-Use period T, LSF stands for locational safety factor, which adjusts the TUoS charges to cover the locational transmission costs for contingency and outage [53].

6.4 Demonstration System

The proposed method is demonstrated in a modified IEEE 14-bus power system [114], as shown in Figure 6-2.

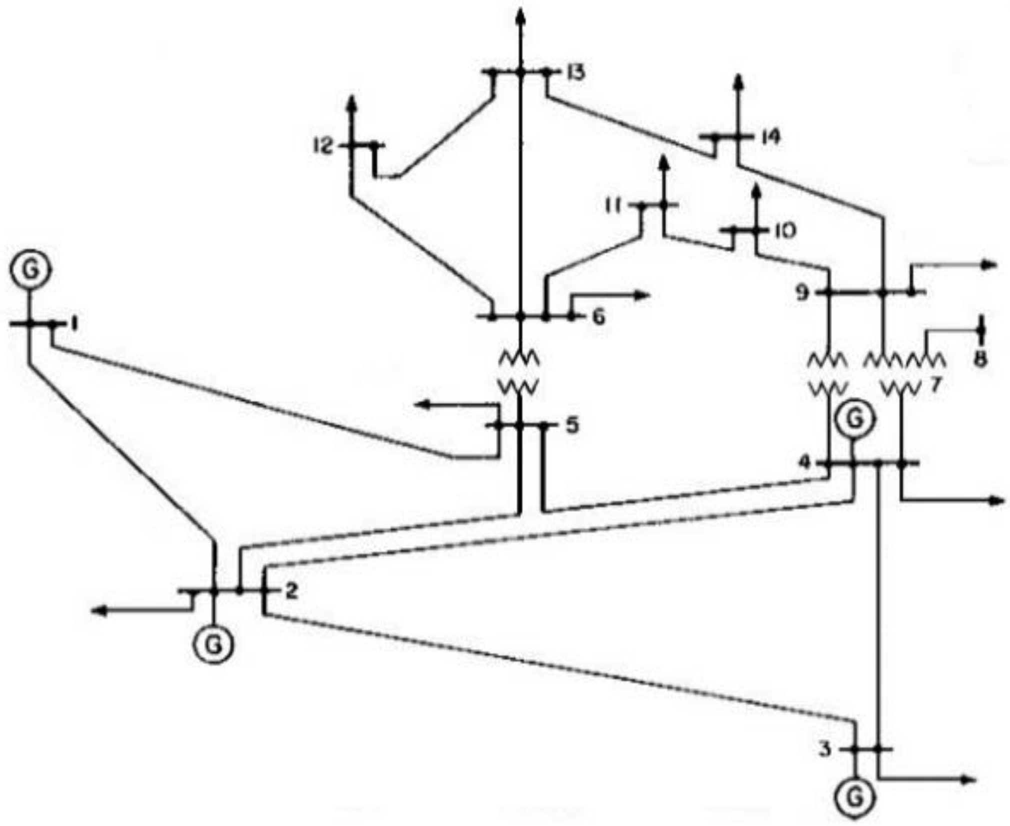


Figure 6-2 Modified IEEE 14 Bus Power System

6.4.1 System Parameters

The generation and demand parameters for the demonstration system are the same as presented in section 4.4.1.

The network parameters are stated in in Table 6-1. The main assumptions are:

- Network impedances are available from [114].

- Transmission losses and outages are not considered.

- Branch capacity limits are set based on the outputs from employing the method proposed in [87], which is able to consider the N-1 contingency.

Table 6-1 Network Parameters for Modified IEEE 14 Bus Power System

Branch	***From Node***	***To Node***	***Capacity (MW)***	***Length (km)***	***Expansion Factor***
B_1	1	2	115	150	1
B_2	1	5	55	200	2
B_3	2	3	55	250	1.5
B_4	2	4	50	250	1
B_5	2	5	50	150	1
B_6	3	4	20	100	1
B_7	4	5	50	100	1
B_8	4	7	40	0	0
B_9	4	9	30	0	0
B_{10}	5	6	50	0	0
B_{11}	6	11	15	50	0.5
B_{12}	6	12	15	80	0.5
B_{13}	6	13	25	100	0.5
B_{14}	7	8	20	10	0.5
B_{15}	7	9	40	0	0
B_{16}	9	10	15	30	0.5
B_{17}	9	14	20	80	0.5
B_{18}	10	11	15	30	0.5
B_{19}	12	13	15	50	0.5
B_{20}	13	14	15	80	0.5

- Node N_8 is chosen as the slack bus.
- Branch length are assumed to reflect the geographical distance between nodes.
- Expansion Constant (*EC*) is set as £17.013/MW/km/year, referred to [53].
- Expansion Factor represents the cost of other types of overhead lines and cables relative to Expansion Constant, its unit is 1.

6.4.2 Simulation Procedure

The calculation and allocation of congestion costs employ the economic dispatch function in Matpower package [99], as explained in section 4.4.2. The other steps of the proposed method are achieved by Matlab programming. 'Cluster' function in Matlab is employed to derive Time-of-Use periods. Matpower package is also employed to calculate the distance (MW*km) in the proposed method.

For the modified IEEE 14-bus power system, it takes about 30 minutes to obtain the Time-of-Use periods (the calculation and allocation of time-series congestion costs take most of the time), but only about 2 minutes to obtain the Time-of-Use TUoS charges. The configuration of the desktop employed in this research work is an Intel Core 2 6400@ 2.13GHz CPU and a 4GB memory.

6.5 Results and Discussion

The year-round operation of the demonstration system have been presented in section 4.5.1. Time-series total congestion costs and branch congestion costs have been given in section 5.5.1. Time-series nodal congestion costs can be shown in a similar way. This chapter focuses on the identification of Time-of-Use periods for each node and corresponding TUoS charges for various generation technologies.

6.5.1 Annual Branch and Nodal Congestion Costs

The annual congestion cost for the demonstration system is £2.64×10^5. Table 6-2 shows the congestion costs allocated to branches (BCC_l). Table 6-3 shows congestion cost allocated to nodes (NCC_i).

Table 6-2 Branch Congestion Cost

	BCC_1	BCC_2	BCC_3	BCC_4	BCC_5	BCC_7	*Total*
£ (10^5)	0.32	1.05	0.87	0.23	0.001	0.16	2.64

Table 6-3 Nodal Congestion Cost

	NCC_1	NCC_2	NCC_3	NCC_4	NCC_5
£(10^5)	1.677	0.360	0.426	0.127	0.0002

Only N_1-N_4, where large generation and demand are connected, are allocated large congestion costs. The other nodes are allocated miniscule congestion costs. This chapter only intends to show Time-of-Use TUoS charges for various generation technologies, such as those connected at nodes N_1–N_4. Hence, the TUoS charges for other nodes (mainly demand connection points) are out of the scope of this chapter.

6.5.2 Time-of-Use Periods

As explained in section 5.5.3, majority of congestions in the demonstration system occur in winter. As Time-of-Use periods are determined by grouping congested time periods in the proposed method, there are only Time-of-Use periods in winter workdays and weekends for the demonstration system.

In the proposed method, Time-of-Use periods are obtained by clustering the time periods with similar congestion costs in a typical day. Therefore, time periods with high congestion costs, which indicate severe congestions thus require high network investments, are clustered together; time periods with low congestion costs, which indicate slight congestions thus require low network investments, are clustered together.

Figure 6-3 and Figure 6-4 give the Time-of-Use periods of winter workdays and weekends for node N_1- N_4. The horizontal axis presents 24 hours in a day. The vertical axis shows the magnitude of congestion costs. Please note that the vertical axis is NOT TUoS charges (as the proposed method employs time-series nodal congestion cost to obtain Time-of-Use periods), but high congestion costs do imply high investment requirements, thus high TUoS charges should be set for these periods.

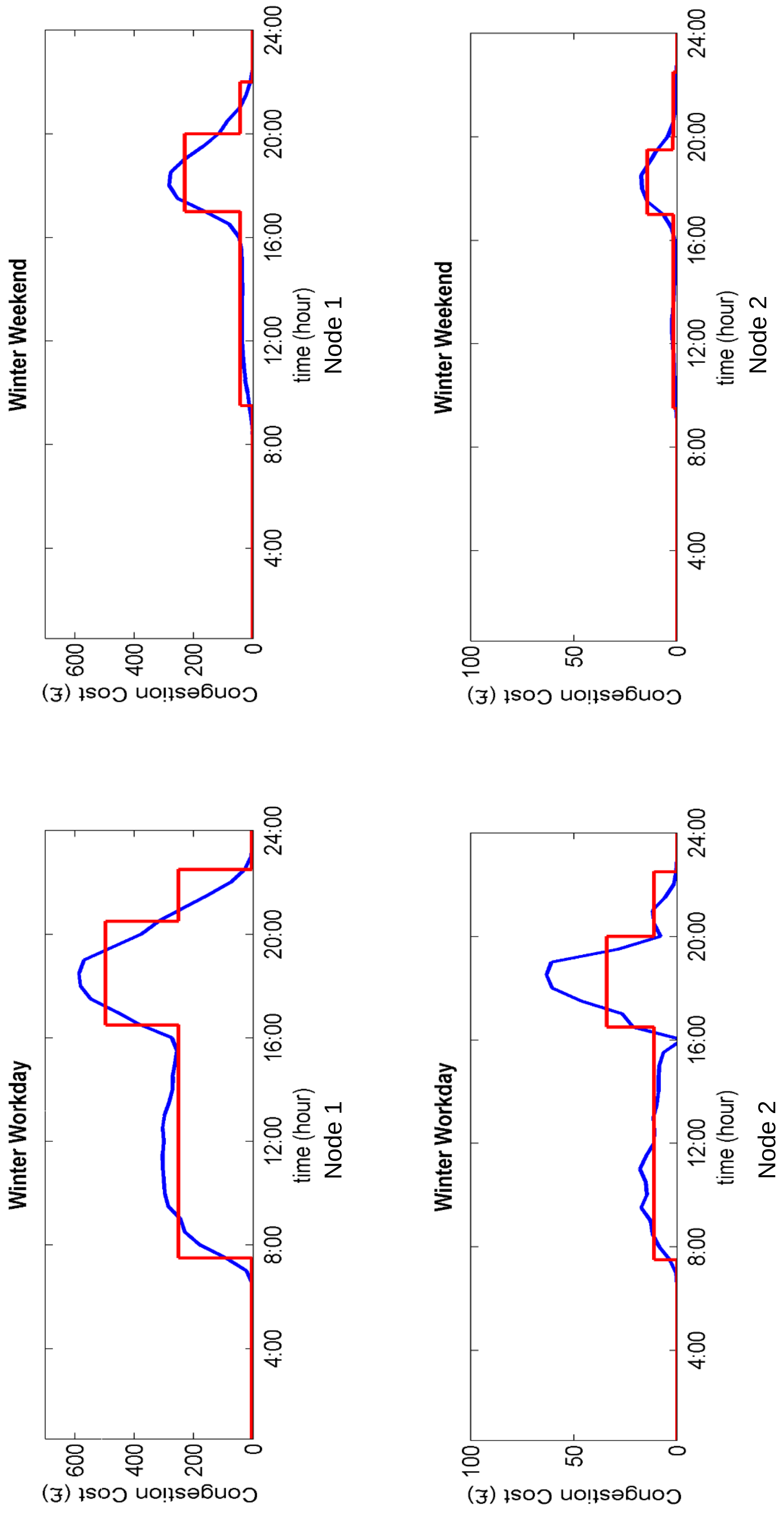


Figure 6-3 Time-of-Use Periods for Node 1 & Node 2

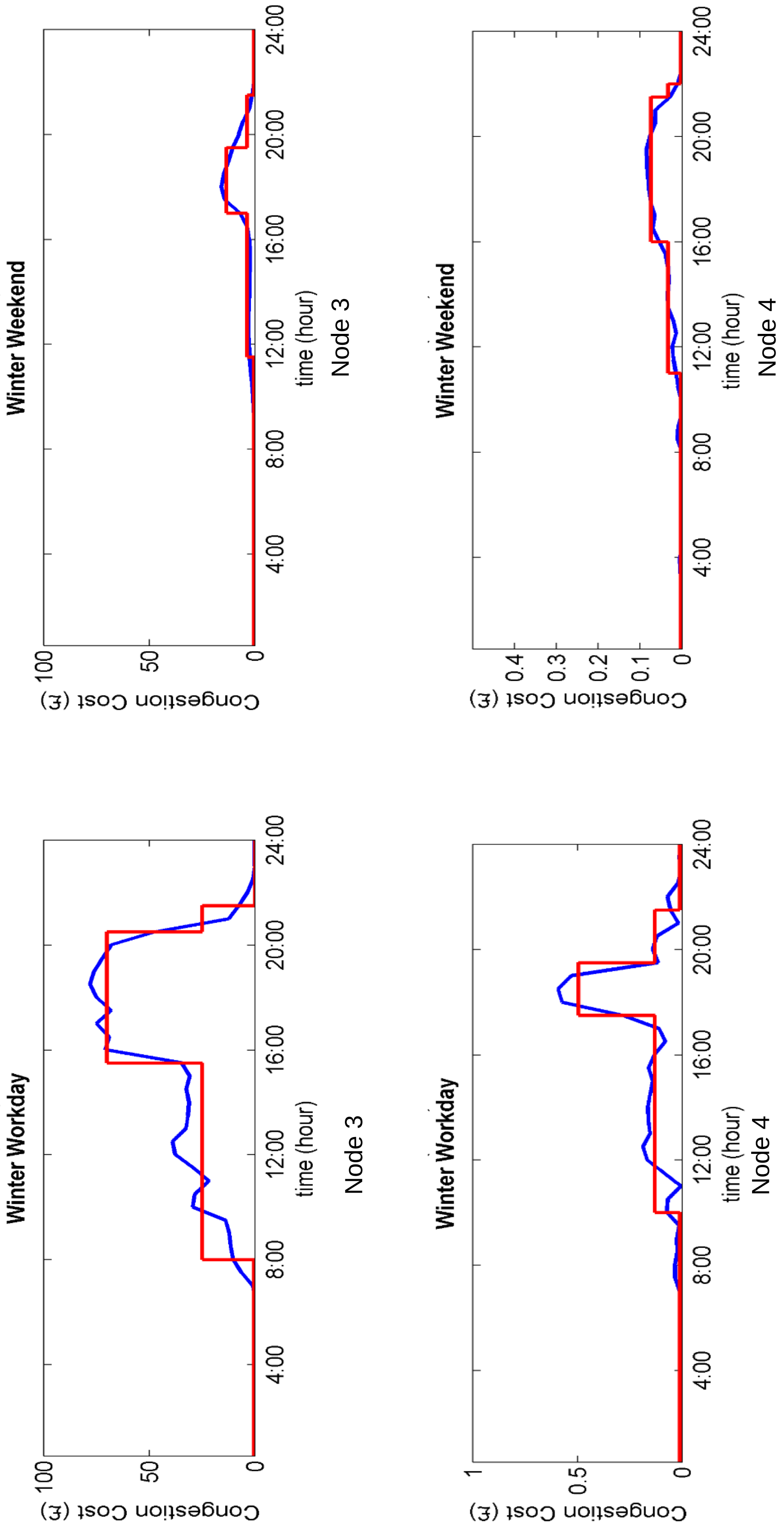


Figure 6-4 Time-of-Use Periods for Node 3 & Node 4

In Figure 6-3 and Figure 6-4, the blue curves stand for average congestion costs along 24 hours. The red step lines stand for the average congestion costs for Time-of-Use periods for this typical day. The time points which steps occur are the start and end time for Time-of-Use periods.

It is apparent that high congestions always occur from late afternoon to early evening. Medium congestions occupy the periods before and after high congestions. Slight congestions take the rest of the day. Three levels of system congestions divide 24 hours into 5 Time-of-Use periods. (Exact values are given in Appendix A-7.)

By comparing the steps lines in Figure 6-3 and Figure 6-4, it is clear that the Time-of-Use periods are different for different nodes. In the proposed method, Time-of-Use periods are specific for each node, but the TUoS charges for generators connected at the same node are different.

6.5.3 Inputs for TUoS Charging

Table 6-4 gives the demand levels in node N_1-N_4 for Time-of-Use periods in winter workdays and weekends. Low, medium and high congestions are judged based on the magnitude of congestion costs.

It is apparent that high demands normally lead to severe congestions, low demands normally cause slight congestions.

Table 6-4 Demand Levels for Time-of-Use Periods

Node	***Winter Workday***			***Winter Weekend***		
	Low Congestion	*Medium Congestion*	*High Congestion*	*Low Congestion*	*Medium Congestion*	*High Congestion*
N_1	0.580	0.761	0.837	0.551	0.673	0.755
N_2	0.580	0.763	0.841	0.548	0.676	0.757
N_3	0.598	0.769	0.824	0.570	0.686	0.757
N_4	0.621	0.784	0.854	0.562	0.671	0.729

Table 6-5 compares the annual load factors for generators and their load factors specified for Time-of-Use periods in winter workday and weekend.

Annual load factor reflects a generator's average behaviours throughout a year. But load factors specified for Time-of-Use periods could better reflect generator's contribution to different levels of system congestions during different times. For example, generator G_2's load factors during high congestion periods are smaller than those during medium congestion periods. This is because that G_2 is asked to reduce its output during high congestion periods. As another example, the load factors of generator G_4 and G_5 during high congestion periods are much higher than those in other periods. This is because that they are asked to increase their outputs during high congestion periods.

Table 6-5 Load Factors for Time-of-Use Periods

Node	*Generator*	*Technology*	*Annual Load Factor*	*Winter Workday*			*Winter Weekend*		
				Low	*Medium*	*High*	*Low*	*Medium*	*High*
N_1	G_1	Nuclear	1.00	1.00	1.00	1.00	1.00	1.00	1.00
	G_2	Coal	0.80	0.75	0.86	0.78	0.70	0.91	0.89
	G_3	Wind	0.29	0.38	0.38	0.39	0.35	0.36	0.35
N_2	G_4	Coal	0.22	0.04	0.64	0.91	0.02	0.24	0.63
	G_5	Gas	0.01	0.00	0.03	0.13	0.00	0.00	0.02
N_3	G_6	Gas	0.05	0.01	0.17	0.41	0.00	0.03	0.15
	G_7	Wind	0.29	0.38	0.38	0.39	0.35	0.37	0.35
N_4	G_8	Wind	0.29	0.38	0.39	0.39	0.35	0.37	0.35

Table 6-6 specifies the expansion constants for Time-of-Use periods in winter workday and weekend. These expansion constants are for each time period (0.5h), thus small in the order of magnitude (10^{-3}). Their dimension are £ /MW/km.

Since expansion constants for Time-of-Use periods are designed based on the level of congestion costs, high expansion constants are set for high congestion periods and vice versa.

Table 6-6 Expansion Constants for Time-of-Use Periods

Node	***Winter Workday***			***Winter Weekend***		
	Low Congestion (£/MW/km)	*Medium Congestion (£/MW/km)*	*High Congestion (£/MW/km)*	*Low Congestion (£/MW/km)*	*Medium Congestion (£/MW/km)*	*High Congestion (£/MW/km)*
N_1	0.045×10^{-3}	2.61×10^{-3}	5.14×10^{-3}	0.009×10^{-3}	0.447×10^{-3}	2.38×10^{-3}
N_2	0×10^{-3}	2.48×10^{-3}	7.55×10^{-3}	0.004×10^{-3}	0.392×10^{-3}	3.18×10^{-3}
N_3	0×10^{-3}	2.45×10^{-3}	6.85×10^{-3}	0.024×10^{-3}	0.343×10^{-3}	1.32×10^{-3}
N_4	0.182×10^{-3}	2.29×10^{-3}	8.68×10^{-3}	0.053×10^{-3}	0.591×10^{-3}	1.29×10^{-3}

6.5.4 Time-of-Use TUoS Charges

Figure 6-5 and Figure 6-6 show the TUoS charges for all generators (exact values are given in Appendix A-7). Generators are differentiated by colours. The horizontal axis shows the low, medium and high congestion periods. The vertical axis gives the value of TUoS charges.

- Node N_1 (Generator G_1, G_2 and G_3)

TUoS charges in high congestion periods are several times larger than those in medium congestion periods, whereas TUoS charges for low congestion periods are about zero. The results show that the proposed method can recognize the impacts of congestion costs over different times on network investments: severe congestion requires high investments, thus high TUoS charges should be set.

Under the proposed method, generators at the same location face different TUoS charges based on the technologies they employ (essentially their load factors specified for Time-of-Use periods). Nuclear generator G_1 faces the highest charges, reflecting the fact that it normally operates at full capacity thus its load factors are high. Renewable generator G_3 faces smallest charges, reflecting the fact that its output is limited by the availability of renewable resources thus its load factors are small.

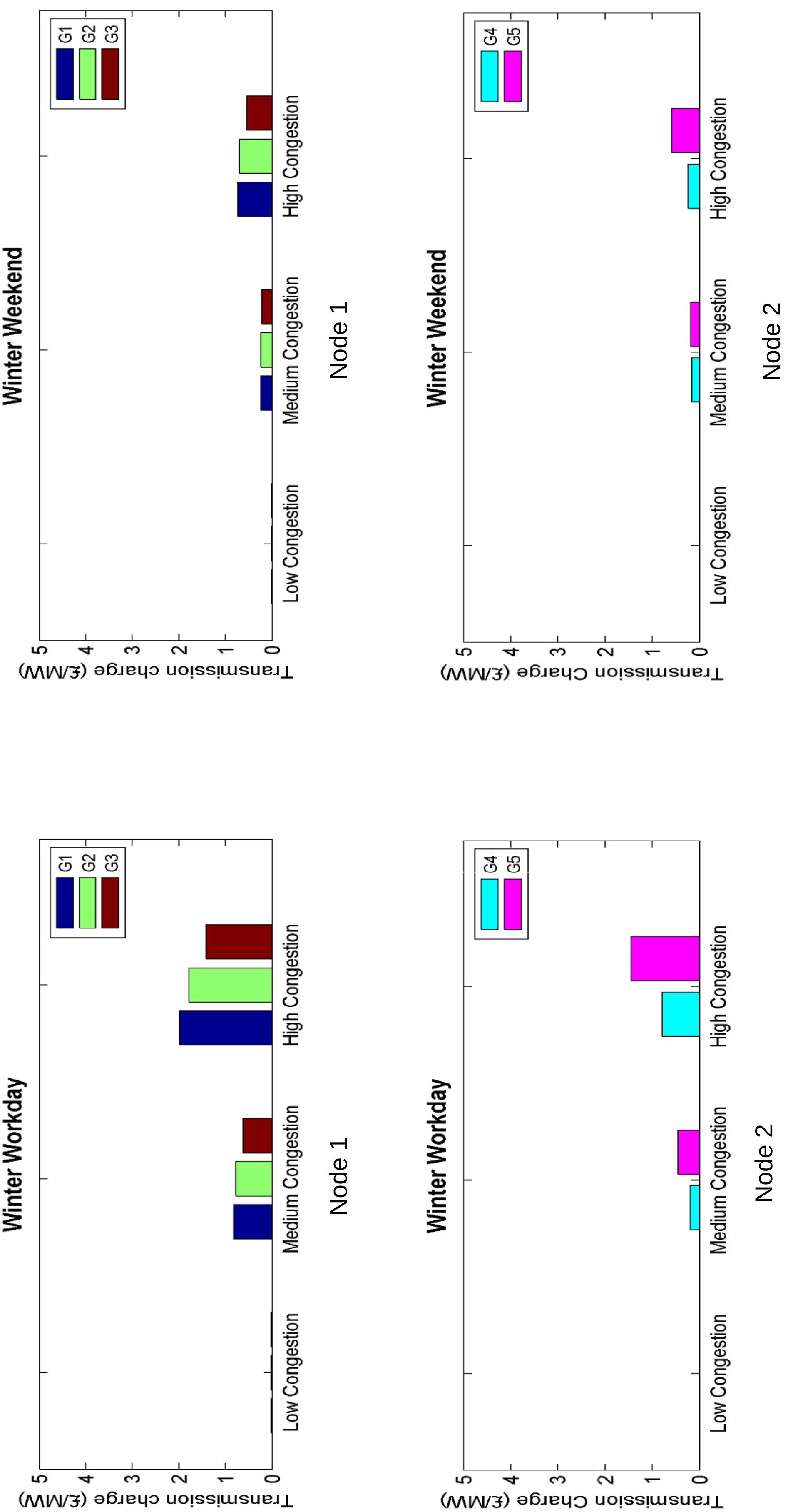


Figure 6-5 TUoS Charges for Generators connected at Node 1 & Node 2

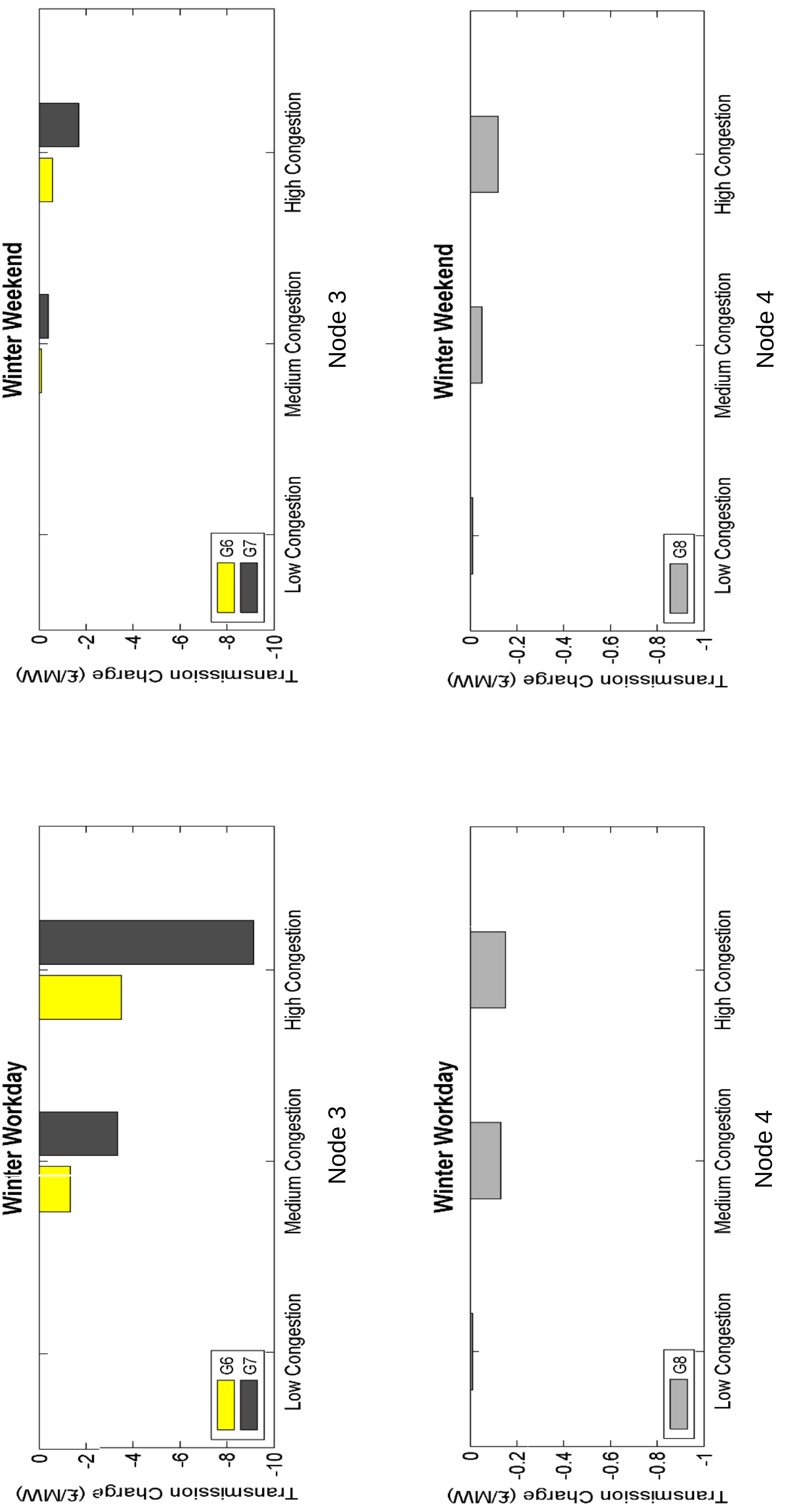


Figure 6-6 TUoS Charges for Generators connected at Node 3 & Node 4

- Node N_2 (Generator G_4 and G_5)

Same philosophy applies to the analysis for generators connected at node N_2. Generators face higher charges in high congestion periods than other times.

Under the proposed method, both coal-fired generator G_4 and gas-fired generator G_5 face positive TUoS charges, but the magnitude of their TUoS charges are different. By employing the principle of power flow based MW*km method, positive TUoS charges come from the fact that marginal capacity increases from G_4 and G_5 lead to increase in the distances that electricity has to travel to meet demand.

- Node N_3 (Generator G_6 and G_7)

Same philosophy applies to the analysis for generators connected at node N_3. Both G_6 and G_7 face negative TUoS charges, reflecting that marginal capacity increases from G_6 and G_7 lead to decrease in the distance that electricity has to travel to meet demand.

- Node N_4 (Generator G_8)

Same philosophy applies to the analysis for generator connected at node N_4. G_8 faces negative TUoS charges, reflecting that marginal capacity increase from G_8 leads to decrease in the distance that electricity has to travel to meet demand.

By analysing the TUoS charges, it is concluded that the proposed method is able to:

- provide time-specific TUoS charges for Time-of-Use periods in which network users make different contributions to branch power flows, consequently system congestions and required transmission investments. If network users could response to these time-specific signals by adjusting their outputs to avoid high TUoS charges, the efficiency of utilizing the existing networks would be improved.
- differentiate various generation technologies connected at the same locations. Potential generation investments would be attracted to locations with profitable network charges, thus promoting appropriate generation expansion. This will ultimately reduce or defer the long-run network investments.

6.6 Comparing with Previous Methods

The proposed method in Chapter 6 improves the existing ICRP method in being able to differentiate generation technologies and derive time-specific TUoS charges in the form of Time-of-Use. It is called as ToU-ICRP method hereafter.

Table 6-7 summarizes the signs of TUoS charges for generators from the existing ICRP method (Chapter 4), T-LRIC method (Chapter 4), ToU-LRIC method (Chapter 5) and ToU-ICRP method (Chapter 6) ('+' for positive TUoS charge and '-' for negative TUoS charge).

Table 6-7 Sign of TUoS Charges in 4 Methods

Node	*Generator*	*ICRP*	*T-LRIC*	*ToU-LRIC*	*ToU-ICRP*
N_1	G_1	+	+	+	+
	G_2	+	+	+	+
	G_3	+	+	+	+
N_2	G_4	+	-	-	+
	G_5	+	-	-	+
N_3	G_6	-	+	+	-
	G_7	-	-	-	-
N_4	G_8	-	-	-	-

It is apparent that the signs of TUoS charges from the existing ICRP method and ToU-ICRP method are consistent. ToU-ICRP method has advantages in providing time-specific TUoS charges and differentiating generators that employ different technologies connected at the same location.

However, it is also apparent that the signs of TUoS charges from ICRP/ToU-ICRP methods and T-LRIC/ToU-LRIC methods are inconsistent. By employing the principle of power flow based MW*km method, both the exiting ICRP method and ToU-ICRP method can only reflect the impacts of network users on the branch power flows (the distance that electricity has to travel to meet demand) but not congestion costs, whose increase however trigger transmission investments. In other words, they cannot reflect the rationale of transmission investments under the economic criteria.

Table 6-8 summarizes the comparisons between the four TUoS charging methods in terms of the following criteria.

Table 6-8 Comparison of 4 TUoS Charging Methods

	Criteria	*ICRP*	*T-LRIC*	*ToU-LRIC*	*ToU-ICRP*
1	Are TUoS charges locational?	Yes	Yes	Yes	Yes
2	Do TUoS charges consider the influence of year-round operation?	No	Yes	Yes	Yes
3	Are TUoS charges specified for generation technologies?	No	Yes	Yes	Yes
4	Do TUoS charges reflect which branch requires investment?	No	Yes	Yes	No
5	Are TUoS charges specified for different times?	No	No	Yes	Yes
6	How is the calculation speed?	Fast	Slow	Very slow	Medium

1. Are TUoS charges locational?

All four TUoS charging methods provide locational TUoS charges for network users.

2. Do TUoS charges consider the influence of year-round system operation?

The existing ICRP method only considers the system operation during the period of system peak. T-LRIC method and ToU-LRIC method can reflect the trade-offs between operational and investment costs by quantifying the impacts of annual congestion cost or time-series congestion costs on the investment time horizons of transmission networks. ToU-ICRP method considers the year-round system operation by quantifying specific expansion constants for different times in a year.

3. Are TUoS charges specified for various generation technologies?

The existing ICRP method provides locational TUoS charges for network users regardless of generation technologies. The other three methods provide technology-specific TUoS charges.

T-LRIC method and ToU-LRIC method differentiate generation technologies via identifying their impacts on the investment time horizons of transmission branches. However, ToU-ICRP method employs generators' load factors to differentiate generation technologies.

4. Do TUoS charges reflect which branch requires investment?

Due to the MW*km principle in ICRP method, both the exiting ICRP method and ToU-ICRP method cannot recognise which branch requires to be invested. A basic assumption in ICRP method is that existing networks are fully utilized and any additional power injection requires immediate network investments.

T-LRIC method and ToU-LRIC method can identify which branch requires investment and even when investments are required.

5. Are TUoS charges specified for different times?

This question can be answered literally. TUoS charges under the existing ICRP method and T-LRIC method are not time-specific. ToU-LRIC method and ToU-ICRP method can provide time-specific TUoS charges in the form of Time-of-Use.

In ToU-LRIC methods, Time-of-Use periods are specific for each generation technologies in a location, and the corresponding TUoS charges are obtained by clustering time-series TUoS charges.

However, in ToU-ICRP method, Time-of-Use periods are determined via clustering time-series nodal congestion costs. Time-of-Use periods are specific for a node. But the corresponding TUoS charges for different generation technologies are different.

6. How is the calculation speed?

The existing ICRP method only takes 20 seconds to get TUoS charges. T-LRIC method takes about 1 hour. ToU-LRIC method requires over 20 hours and ToU-ICRP method only takes about 30 minutes. The configuration of the desktop employed in this research work is an Intel Core 2 6400@ 2.13GHz CPU and a 4GB memory.

In summary, there is no doubt that existing TUoS charging methods need to be improved for the low carbon transition of the power industry. All the proposed TUoS charging methods in this thesis enhance the cost-reflectivity and economic efficiency of TUoS charges in differentiating generation technologies and/or providing time-specific signals.

If time-specific feature is too complex for TUoS charges, T-LRIC method is the preferred method as it can exactly reflect the trade-offs between operational and investment costs in transmission investments under the economic criteria and differentiate the impacts of network users in advancing or deferring network investments. ToU-LRIC method is poor in simplicity and transparency, but it does provide the most comprehensive TUoS charges. ToU-ICRP method is more likely to be accepted by network users and industry regulator, but it fails to identify network users' influences in advancing or deferring network investments.

6.7 Chapter Summary

The ToU-ICRP method proposed in this chapter improves the existing ICRP method. It is able to

- reflect the typical conditions of system congestions;
- offer time-specific TUoS charges in the form of Time-of-Use;
- differentiate generation technologies connected at the same location.

The proposed method employs a two-stage procedure:

- The first stage aims to identify the Time-of-Use periods. Firstly, time-series congestion costs for the whole system are allocated to nodes. Then, Time-of-Use periods are obtained through clustering the time-series nodal congestion costs, aiming to find the representative periods for different levels of system congestions, which impose different impacts on network investments. In the proposed method, Time-of-Use periods are specific for each node.

- The second stage derives TUoS charges for different generators under Time-of-Use periods. The fundamental principles of ICRP method are retained. But expansion constants for Time-of-Use periods are designed based on the levels of congestion costs in these periods. In the scaling of generation capacity down to demand, generator capacities are multiplied by their load factors under corresponding Time-of-Use periods. By quantifying the changes in DC power flows due to a marginal capacity increase from network users, TUoS charges for each network user are determined in the form of Time-of-Use charges.

The proposed method is demonstrated on a modified IEEE 14 bus system.

ToU-ICRP method offers time-specific TUoS charges for network users. In the short-run, network users would adjust their outputs or demands to avoid high network charges and reduce system congestions, thus promoting the efficient utilization of existing networks.

By employing load factor specified for Time-of-Use periods, generators that employ different technologies at the same location are differentiated. This can attract effective generation technology to locations with profitable network charges, therefore incentivizing appropriate generation expansion and ultimately deferring or reducing network investments in long-run.

All the proposed TUoS charging methods in this thesis enhance the cost-reflectivity and economic efficiency of TUoS charges in differentiating generation technologies and/or providing time-specific signals. If time-specific feature is too complex for TUoS charges, T-LRIC method is the preferred method. If not, ToU-LRIC method provides the most comprehensive TUoS charges. Even ToU-ICRP method is more likely to be accepted by network users and industry regulator, one of its obvious disadvantages is that it fails to reflect network users' influences in advancing or deferring network investments.

Chapter 7

Conclusions and Future Works

THIS chapter summarizes the key findings and major contributions from this research, and proposes the future improvements.

7.1 Key Findings & Major Contributions

Transmission Use of System (TUoS) charges are against generators and suppliers for their use of transmission networks. TUoS charges basically allow transmission companies to cover their costs in network maintenance and investments, as well as provide a reasonable rate of return for the sustainable development of transmission networks. In the competitive environment, TUoS charges also play a significant role in providing cost-reflective and economically efficient signals to the current and future network users, promoting effective utilization of existing networks and minimising future network expansion.

The majority of existing TUoS charging methods were designed for traditional power systems that are dominated by conventional generation. Traditional transmission investment philosophy is to support the power flows during the period of system peak. As conventional generation are controllable and available for most of time, they make their maximum utilization of transmission networks during the period of system peak. Consequently, existing transmission charging methods provide fixed annual TUoS charges based on a single scenario of system peak.

In recent years, many countries around the world set ambitious goals of renewable development. However, due to the intermittent feature of renewable energy, renewable generators cause more frequent transmission congestions, not limited to high demand periods but anytime when renewable resources are abundant. Renewable generation require more transmission capacity to be built, but these capacities will be under-utilized at other times. Therefore, under the low carbon transition of the power industry, transmission investments need to be justified based on the trade-offs between operational costs due to generation re-dispatch (congestion costs) and investment costs from network upgrades.

Under the low carbon transition of the power industry, the existing TUoS charging methods, such as Investment Cost Related Pricing (ICRP) method, become inefficient due to the following reasons:

- Existing TUoS charging methods treat generators the same irrespective of generation technologies. They fail to recognise the significant difference of availabilities between conventional and renewable generation. For a power system with substantial renewable generation, conservatively following the existing TUoS charging methods would make renewable generation facing TUoS charges with low cost-reflectivity, thus impeding the appropriate future generation expansion.

- Existing TUoS charging methods derive TUoS charges based on a single scenario of system peak. They cannot reflect the trade-offs between operational and investment costs, thus presenting poor cost-reflectivity in TUoS charges. Moreover, they ignore the fact that the level of transmission investments required are triggered by system conditions throughout the year, thus failing to charge network users based on their contributions to transmission investment requirements at different times.

This research work sets out to develop novel Transmission Use of System charging methods for the low carbon transition of the power industry, reflecting the contribution to network investments from different generation technologies, different locations and critically different times.

In this thesis, transmission congestion costs are used to quantify the trade-offs between operational and investment costs, as the increase of congestion costs would bring forward the investment decisions. It firstly identifies the key drivers of congestion costs under the low carbon transition, which are generation technology (including generators' production costs and availabilities), transmission capacity and demand profile. Secondly, it summarizes the key conditions of transmission congestions, which vary significantly between locations and over times. Transmission congestions are not evenly distributed in transmission systems, i.e. specific branches may contribute to the majority of system congestions. Transmission congestions are dynamically varying at different times, but high congestions appear at relatively fixed days in a year and fixed hours during a day (such as during daily demand peak in winter workdays).

On this basis, this thesis creatively converts the above key findings into cost-reflective and economically efficient TUoS charging methods. The fundamental innovations include:

1. **reflecting the trade-offs between operational and investment costs in transmission investments under the economic criteria**

In the proposed T-LRIC and ToU-LRIC methods, the time horizons of transmission investments, which are determined by comparing congestion costs and investment costs in a future time, are chosen as the approach to derive economically efficient forward-looking TUoS charges.

Among the identified key drivers, the calculation of congestion costs make it possible to reflect the impacts of generation technology on the requirement of transmission capacity. In the highlighted key conditions, the proposed methods recognises the various locations of transmission congestions.

The investment time horizons for different congested branches are normally 15~20 years from the present, reflecting the effects of congestion management in deferring transmission investments. When compared with the existing ICRP method, TUoS charges from the proposed methods can continuously adjust every year (for example in Section 4.6, TUoS charges for a wind farm under T-LRIC method will increase from £5400/MW/year to £9800/MW/year for the next 10 years), reflecting the extent of system congestions and the degree of urgency in network investments. While ICRP method only reflects the asset costs, TUoS charges faced by network users stay largely stable if there is little network investment.

In doing so, TUoS charges can reflect the trade-offs between operational and investment costs in transmission investments under the economic criteria. Moreover, the magnitudes of TUoS charges can reflect network users' influences in advancing or deferring transmission investments.

2. **differentiating various generation technologies to improve cost-reflectivity and guide appropriate generation expansion**

In the proposed T-LRIC and ToU-LRIC methods, different generation technologies are differentiated based on their impacts on investment time horizons, which are essentially determined by their availabilities and production costs. These impacts are then translated to TUoS charges, which are defined as the difference between the present values of transmission investments with and without incremental capacity change from each generation technology.

Under the T-LRIC and ToU-LRIC methods, advancing investments would lead to positive TUoS charges and deferring investments would lead to negative TUoS charges. For example in Section 4.5.4, under T-LRIC method, the renewable generator faces less than one third TUoS charges (£6315/MW/year) compared to the conventional generators connected at the same location (£21281/MW/year for nuclear and £19516/MW/year for coal), reflecting the fact that renewable generator contributes less to the annual congestion cost thus requires lower or later transmission investments. For the same renewable generation technology, generators connected at different locations face different TUoS charges (£6315/MW/year far from demand and £-8008/MW/year near to demand), reflecting the fact that generation located far away from demand would require more transmission infrastructure to reach demand.

In doing so, future generation expansion (conventional or renewable) would be attracted to appropriate locations, thus reducing congestion costs and ultimately investment costs. Critically, by providing cost-reflective TUoS charges to different generation technologies, the cross-subsidies between renewable and conventional generation will be removed, which in turn enable the efficient development of low carbon power systems.

3. **providing time-specific TUoS charges to promote the efficient utilization of existing networks**

In the proposed ToU-LRIC method, the time-specific TUoS charges are obtained by clustering time-series TUoS charges. One year is first divided into eight typical days (4 seasons and workday/weekend). Then, a typical day is divided into Time-of-Use periods, reflecting different conditions of system congestions and the required transmission investments. In the proposed ToU-ICRP method, the time-specific TUoS charges are based on the clustering of time-series nodal congestion costs. A similar method is employed to determine Time-of-Use periods.

Among the identified key drivers, the calculation of congestion costs can reflect the impacts of generation technology on the requirement of transmission capacity. In the highlighted key conditions, ToU-LRIC method can recognise the various locations and times of transmission congestions.

For example in Section 5.5.3, under the ToU-LRIC method, the winter workday TUoS charges for nuclear generator are £15.80/MW, £2.50/MW and £0.50/MW for high congestion period (around £1000 per half-hour and roughly from 16:30 to 20:30), medium congestion period (around £400 per half-hour and roughly from 09:00 to 16:30 and from 20:30 to 21:00) and low congestion period (nearly £0 per half-hour and occupy the rest of the day) respectively, indicating that high congestions require earlier or larger transmission investments thus ought to face higher TUoS charges. For renewable generator connected at the same location, these figures become £5.11/MW, £0.85/MW and £0.03/MW respectively, indicating renewable generators' low contribution to system investment requirements.

In doing so, time-specific TUoS charges can incentivize network users to proactively adjust their short-run network using behaviours of the existing networks, thus reducing transmission congestions throughout the year and promoting the efficient utilization of the existing networks.

To summarise, the three innovations embodied in the proposed TUoS charging methods in this thesis can provide a level playing field for different generation technologies during different times, thus effectively contributing to the low carbon transition of the power industry.

7.2 Future Works

In spite of the valuable findings and innovative contributions made in this research work, there are still some aspects that could be improved after this thesis.

1. **Considering Various Demand Types in TUoS Charging**

An efficient TUoS charging method should offer economic signals to all network users, both generation and demand. The proposed methods in this thesis effectively enhance the efficiency of TUoS charges in guiding the technology choosing of future generation and promoting efficient utilization of existing networks. However, the proposed methods employ a single profile for all kinds of demand, thus ignoring the various impacts from different types of consumers on transmission investments. For example, residential consumers can easily increase the daily demand peak, thus requiring immediate network upgrades. But for industrial consumers, they may only contribute to the steady electricity consumption during the daytime, thus requiring network upgrades later. By differentiating demand types, TUoS charges can encourage different types of demands to connect at appropriate locations, thus reducing system congestions and deferring network investments. Time-specific TUoS charges could also be developed for different types of consumers, providing smart signals for their electricity consumption.

2. **Quantitatively Assessing the Benefits of Adopting the Proposed TUoS Charging Methods**

It is widely realized that the existing TUoS charging methods should be improved for low carbon power systems. This thesis successfully answers the questions 'who brings these challenges' and 'how to address them.' This thesis focuses on developing TUoS charging methods for a low carbon future. But the benefits of adopting these proposed methods are not quantitatively assessed, although the demonstration results can qualitatively present their efficiencies. The assessment should be applied in a practical power system with various generation technologies. Moreover, the TUoS charging model should be coupled with a combined generation and transmission expansion planning (GNEP) model. The simulation should inspect the long-run results, such as 10 years. Afterwards, the total costs in system operation, generation and network expansion are compared with the benchmark case that employs the existing TUoS charging method. The adoption of the proposed methods would be persuasive with quantitative benefits.

3. **Incorporating Reliability Driven Transmission Investments into TUoS Charging**

Reliability is still the primary criteria in transmission planning, even with the increasing penetration of renewable generation. For transmission networks, the reliability standards are mainly achieved in network planning, i.e. ensuring a reliable electricity supply in N-1 contingency or higher criteria. The proposed TUoS charging methods in this thesis make the assumption that the transmission network models employed during the derivation of TUoS charges have already satisfied the reliability standard. Thus, the resultant TUoS charges cannot reflect network users' various contributions to system reliability and corresponding requirements in reliability driven transmission investments. Incorporating reliability driven transmission investments into TUoS charging would reflect the overall impacts that network users impose on investment costs, thus providing more cost-reflective and economically efficient signals. A possible solution is a parallel TUoS charging method for reliability driven transmission investments. And the final

TUoS charges include components from transmission investments under both the economic criteria and the reliability criteria.

4. **Quantifying the Impacts of Revenue Recognition on the Cost-reflectivity**

The economic transmission charging methods (such as the proposed methods in this thesis) aim to provide economically efficient signals to network users, but the revenue collected from these TUoS charges can only collect partial of the allowed revenue. In order to guarantee the full recovery of the allowed revenue, a residual TUoS charges, which are calculated by the Postage Stamp method, are employed. This procedure is call “Revenue Recognition”. For example in the UK, the revenue collected from economic TUoS charges only contributes to approximately 25% of the allowed revenue. Socialized residual TUoS charges will inevitably reduce the cost-reflectivity in TUoS charges. To apply the proposed methods into practice, the impacts of Revenue Recognition on the cost reflectivity of TUoS charges should be quantified.

5. **Exploring the TUoS Charges for a System with High Renewable Penetration Level**

In this thesis, the simulation results can clearly prove the efficiencies of the proposed TUoS charging methods, but some observations from the simulation results are not true under any circumstance and for any power system. For example, the proposed TUoS charging methods seem to provide a lower TUoS charges for renewable generators. But in fact, this is specific for the modified IEEE 14 bus power system, whose renewable penetration level is low. To prove the efficiencies of the proposed methods in a broader context, the proposed methods should also be applied to a system with high renewable penetration level.

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Appendix

A-1 Investment Cost Related Pricing Method

TNUoS charges calculation procedure in the current ICRP method is presented below, as shown in Figure A-1 and Figure A-2. (The symbols used in Appendix A-1 are borrowed from reference [52] thus not the same with those used in the main body of the thesis.)

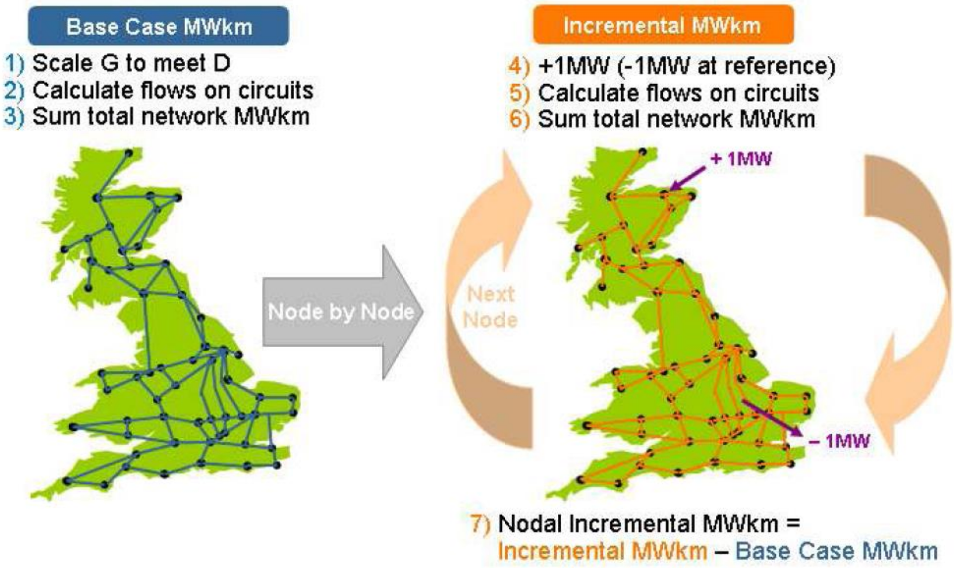


Figure A-1 Existing ICRP method (1)

1. Calculate nodal marginal km

Firstly, all nodal generation is scaled down so that the total generation is equal to total demand.

$$G_n = G'_n \times GSF \tag{Eq. 0-1}$$

where

n	the node n
N_n	the number of nodes
G'_n	the generation at peak time
GSF	the generation scaling factor

$$GSF = \sum_{n=1}^{N_N} D_n \,/\, \sum_{n=1}^{N_N} G'_n \tag{Eq. 0-2}$$

D_n	the forecasted demand

Secondly, calculate the base *M*

$$M = \sum_{l=1}^{N_L} L_l \times |f_l| \qquad \text{(Eq. 0-3)}$$

where

l	power line l
N_l	the number of power lines
L_l	the length of power lines
f_l	the DC power flow on power line l

Thirdly, increase the generation at each node by one unit with an increment of one unit demand at reference node

$$\Delta M_n = M_n - M \qquad \text{(Eq. 0-4)}$$

where

ΔM_n	the nodal marginal *MW*km*
M_n	M with unit change in node n

2. <u>Calculate zonal marginal km</u>

Zone marginal *km* is the average of the nodal marginal km weight by generation/demand.

$$\mathrm{ZM}_{\mathrm{Gg}} = \sum_{\mathrm{n} \in \mathrm{SG}_{\mathrm{g}}} \frac{\mathrm{M_n} \times \mathrm{G_n}}{\mathrm{TG_g}} \qquad \text{(Eq. 0-5)}$$

$$\mathrm{ZM}_{\mathrm{Dd}} = \sum_{\mathrm{n} \in \mathrm{SD}_{\mathrm{d}}} \frac{\mathrm{M_n} \times \mathrm{D_n}}{\mathrm{TD_d}} \qquad \text{(Eq. 0-6)}$$

where

g/d	the generation/demand zones
ZM_{Gg}/ZM_{Dd}	the zone marginal km for generation/demand zones
SG_g/SD_d	the node set for generation/demand zones
TG_g/TD_d	the total generation/demand in generation/demand zones.

3. <u>Calculate initial transport tariff</u>

Initial transport tariff can be calculated by

$$\mathrm{ITT}_{\mathrm{Gg}} = \mathrm{ZM}_{\mathrm{Gg}} \times \mathrm{EC} \times \mathrm{LSF} \qquad \text{(Eq.0-7)}$$

$$\mathrm{ITT}_{\mathrm{Dd}} = \mathrm{ZM}_{\mathrm{Dd}} \times \mathrm{EC} \times \mathrm{LSF} \qquad \text{(Eq.0-8)}$$

where

ITT_{Gg}/ITT_{Dd}	the initial transport tariff for generation/demand zones
EC	the expansion constant,
LSF	Locational Security Factor

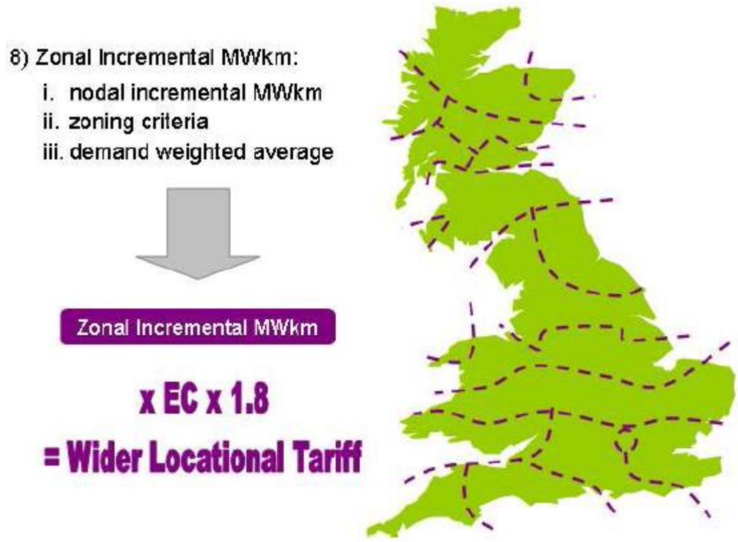


Figure A-2 Existing ICRP method (2)

4. **Calculate correct transport tariff**

The initial transport revenue recovery

$$\mathrm{ITRR_G} = \sum_{g=1}^{ZN_G}\left(\mathrm{ITT_{Gg}} \times \mathrm{TG_g}\right) \quad \text{(Eq. 0-9)}$$

$$\mathrm{ITRR_D} = \sum_{d=1}^{ZN_D}(\mathrm{ITT_{Dd}} \times \mathrm{TG_d}) \quad \text{(Eq. 0-10)}$$

In order to guarantee the ‘correct split’ of revenue between generation and demand (27/73), *PF*, the initial transport revenue recovery needs to be corrected.

$$\mathrm{CTRR_g} = \mathrm{ITRR_G} + \mathrm{C} \times \mathrm{CE} \times \mathrm{LSF} \times \sum_{g=1}^{ZN_G} \mathrm{TG_g} \quad \text{(Eq. 0-11)}$$

$$\mathrm{CTRR_d} = \mathrm{ITRR_D} - \mathrm{C} \times \mathrm{CE} \times \mathrm{LSF} \times \sum_{d=1}^{ZN_D} \mathrm{TD_d} \quad \text{(Eq. 0-12)}$$

where

C	correction constant
$CTRR_G$	the corrected transport revenue recovered from generation zones
$CTRR_D$	the corrected transport revenue recovered from demand zones

$CTRR_G$ and $CTRR_D$ should satisfy the following condition.

$$\mathrm{CTRR_D} = \mathrm{PF} \times (\mathrm{CTRR_G} + \mathrm{CTRR_D}) \qquad \text{(Eq. 0-13)}$$

Then, the corrected transport tariff for generation/demand zones is

$$\mathrm{CTT_{Gg}} = \left(\mathrm{ZM_{Gg}} + \mathrm{C}\right) \times \mathrm{EC} \times \mathrm{LSF} \qquad \text{(Eq. 0-14)}$$

$$\mathrm{CTT_{Dd}} = (\mathrm{ZM_{Dd}} + \mathrm{C}) \times \mathrm{EC} \times \mathrm{LSF} \qquad \text{(Eq. 0-15)}$$

5. <u>Calculate residual tariff</u>

In order to guarantee the full recovery of allowed revenue, the residual tariff for generation/demand RT_G/RT_D is calculated as follows.

$$\mathrm{RT_G} = \frac{[(1-\mathrm{PF})\times \mathrm{TRR}]-\mathrm{CTRR_G}}{\sum_{g=1}^{\mathrm{ZN_G}} \mathrm{TG_g}} \qquad \text{(Eq. 0-16)}$$

$$\mathrm{RT_D} = \frac{[(1-\mathrm{PF})\times \mathrm{TRR}]-\mathrm{CTRR_D}}{\sum_{d=1}^{\mathrm{ZN_D}} \mathrm{TG_d}} \qquad \text{(Eq. 0-17)}$$

where

TRR the total revenue to be recovered through the TNUoS charges

6. <u>Calculate final tariff</u>

The summation of the residual tariff and the corresponding corrected transport tariff of generation/demand zones is the final tariff for generation/demand zones.

$$\mathrm{FT_{Gg}} = \mathrm{CTT_{Gg}} + \mathrm{RT_G} \qquad \text{(Eq. 0-18)}$$

$$\mathrm{FT_{Dd}} = \mathrm{CTT_{Dd}} + \mathrm{RT_D} \qquad \text{(Eq. 0-19)}$$

A-2 Economic Concepts in this thesis

1. Annuity Factor

Annuity factor represents the ratio between a series of regular payments/income and future payment/income, with the reflection of the time value of money [126].

The formula to calculate annuity factor is:

$$\text{Annuity Factor} = \frac{1-(1+r)^{-n}}{r} \quad \text{(Eq. 0-20)}$$

where r is rate per period, n is the number of periods.

In this research work, annuity factor is used to find the annualized investment cost (*AIC*) over assert's life span for a future investment, whose cost is known in advance.

$$AIC_l = \frac{Asset\_cost_l}{Anuity\ Factor} \quad \text{(Eq. 0-21)}$$

where $asset\_cost_l$ is the investment cost for transmission branch l.

In this research work, the life span for transmission assets is 45 years and the discount rate is chosen as 6.9% per annum [127]. Therefore, the annuity factor is 13.77.

2. Present Value

In economics, present value is a future amount of money that has been discounted to reflect its current value, reflecting the time value of money [128].

In this research work, the present value of annualized investment cost of branch l, which is to be built in year t_{inv}, is calculated as follows:

$$PAIC_l^{t_{inv}} = \frac{AIC_l}{(1+d)^{t_{inv}}} \quad \text{(Eq. 0-22)}$$

where d is the discount rate (chosen as 6.9% per annum), t_{inv} is the investment time horizon away from the present.

A-3 Statistical Probability Based Annual Congestion Cost Calculation

This statistical probability approach aims to improve the computational efficiency in calculating annual congestion cost.

Annual congestion cost is basically the sum of congestion costs for 17520 settlement periods, thus requires 35040 (17520*2) economic dispatches in Matpower. This may take up to 1.5 hours.

The statistical probability approach firstly groups the 17520 demands samples to 13 demand levels. Demand level 1 contains the demand samples which are larger than 95% but smaller than 100% of annual demand peak. Demand level 2 contains the demand samples which are larger than 90% but smaller than 95% of annual demand peak. Other demand levels are obtained in a similar way. There are 13 demand levels as demand is never below 35% of annual demand peak in the employed demand data.

Demand value for each level is the average value of the demand samples contained over annual demand peak. Demand level probability for each level is the number of demand samples contained over 17520. Table A-1 gives the values and probabilities for demand levels.

Table A-1 Values and Probabilities for Demand Level

	Demand Level												
	1	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***
Value	96.7 %	91.7 %	86.7 %	81.8 %	76.7 %	71.9 %	67.0 %	62.0 %	57.0 %	52.0 %	47.0 %	52.0 %	38.4 %
Probability	0.6 %	1.5 %	2.7 %	5.5 %	9.8 %	19.9 %	11.1 %	11.0 %	9.2 %	8.7 %	8.4 %	9.7 %	1.9 %

Wind outputs samples are processed in a similar way with demand samples. The only difference is that 17520 wind outputs samples are firstly divided into 13 demand levels, basing on the time when it occurs. Then, 10 wind outputs levels are chosen for 1 demand level. Table A-2 gives the values and probabilities for wind levels.

Table A-2 Values and Probabilities for Wind level

Wind Level	***Wind Value***	***Demand Level***												
		1	***2***	***3***	***4***	***5***	***6***	***7***	***8***	***9***	***10***	***11***	***12***	***13***
1	95 %	4.2 %	6.7 %	4.9 %	2.9 %	3.3 %	1.4 %	1.1 %	0.9 %	0.5 %	0.5 %	0.6 %	0.0 %	0.0 %
2	85 %	0.0 %	5.5 %	3.5 %	3.6 %	4.7 %	3.5 %	3.5 %	4.7 %	3.5 %	3.0 %	4.6 %	5.4 %	1.4 %
3	75 %	8.5 %	5.3 %	5.0 %	5.2 %	7.4 %	5.7 %	4.9 %	5.2 %	5.7 %	7.5 %	7.9 %	3.6 %	3.7 %
4	62 %	11.7 %	11.7 %	10.5 %	11.9 %	8.9 %	5.7 %	5.7 %	5.0 %	4.7 %	6.7 %	7.6 %	6.0 %	3.7 %
5	55 %	12.2 %	8.6 %	9.3 %	9.8 %	10.9 %	7.3 %	7.1 %	7.2 %	7.0 %	8.3 %	7.1 %	5.9 %	1.5 %
6	45 %	7.5 %	10.6 %	9.2 %	12.1 %	10.0 %	11.9 %	13.2 %	10.4 %	9.5 %	9.0 %	6.5 %	8.4 %	8.0 %
7	35 %	12.7 %	9.8 %	12.5 %	13.0 %	9.3 %	11.9 %	11.3 %	12.4 %	10.1 %	10.3 %	11.8 %	13.2 %	10.6 %
8	25 %	17.8 %	14.7 %	13.4 %	10.3 %	10.9 %	14.1 %	12.6 %	13.7 %	14.9 %	13.2 %	11.3 %	14.9 %	13.3 %
9	15 %	13.1 %	13.7 %	15.3 %	16.3 %	12.5 %	15.5 %	17.6 %	17.3 %	17.5 %	16.8 %	16.5 %	17.0 %	26.6 %
10	5 %	12.2 %	13.5 %	16.4 %	15.0 %	22.1 %	23.0 %	22.9 %	23.2 %	26.7 %	24.7 %	26.1 %	25.7 %	31.3 %

In the statistical probability based approach, annual congestion cost *(ACC)* is

$$ACC = \sum(DP(i) \times WP(i,k) \times CC(i,k) \times T) \qquad \text{(Eq. 0-23)}$$

where

i	demand level i
k	wind level k
$DP(i)$	the probability for demand level i
$WP(i, k)$	the probability of wind level (i, k)
$CC(i, k)$	congestion cost under $D(i)$ and $W(i, k)$
$D(i)$	demand value for demand level i
$W(i, k)$	wind value for wind level (i, k)
T	17520, the number of settlement periods in a year

By doing so, the calculation of annual congestion cost only requires 260 (13*10*2) economic dispatches in Matpower, and only takes up to 40 seconds. The error ratio is about 0.5%, thus the accuracy of calculating annual congestion cost is ensured.

A-4 Demonstration Results in Chapter 3

The study in Appendix A-4 analyses the temporal distribution of transmission congestions in different seasons, months and workdays/weekends. It employs the simplified GB power system in section 3.3.2. Transmission congestions across B6 are employed, as shown in Figure A-3.

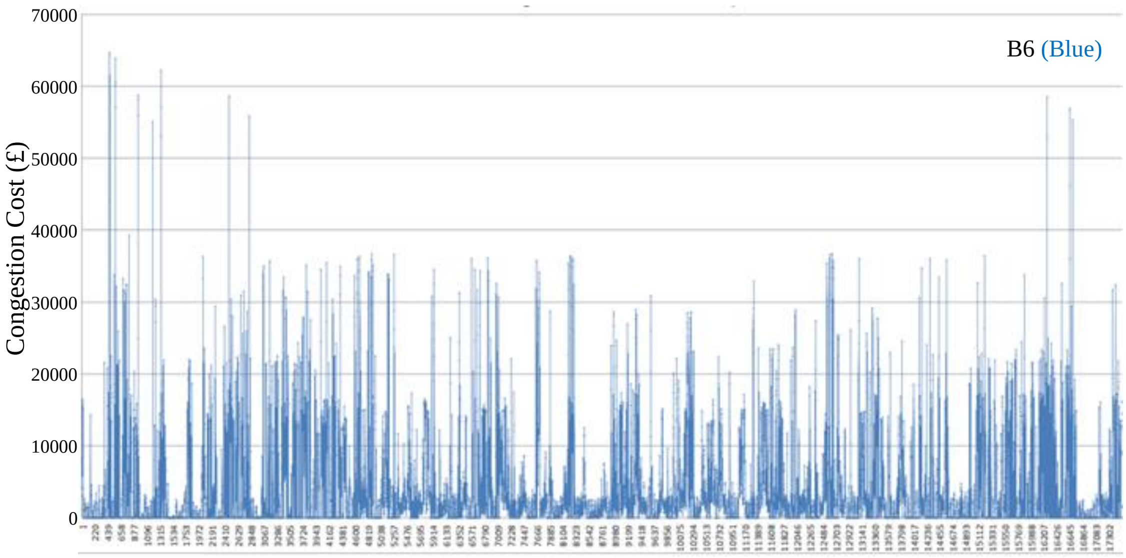


Figure A-3 Year-round Congestion Costs for B_6 in 2011

Figure A-4 shows the share of seasons in when transmission congestions occur. Spring covers March, April, and May; summer covers June, July, and August; autumn covers September, October and November; winter covers December, January, and February.

In Figure A-4, spring occupies the largest share (29.07%), then winter (26.98%), autumn (23.24%), and the smallest share from summer (20.72%). Therefore, transmission congestions are not evenly allocated into different seasons. When introducing the time-specific feature to transmission charges, the influence of seasons should be taken into account.

Figure A-5 shows the share of months in when transmission congestions occur. The months included in each season contribute to a similar shares thus their features have already been reflected in seasons.

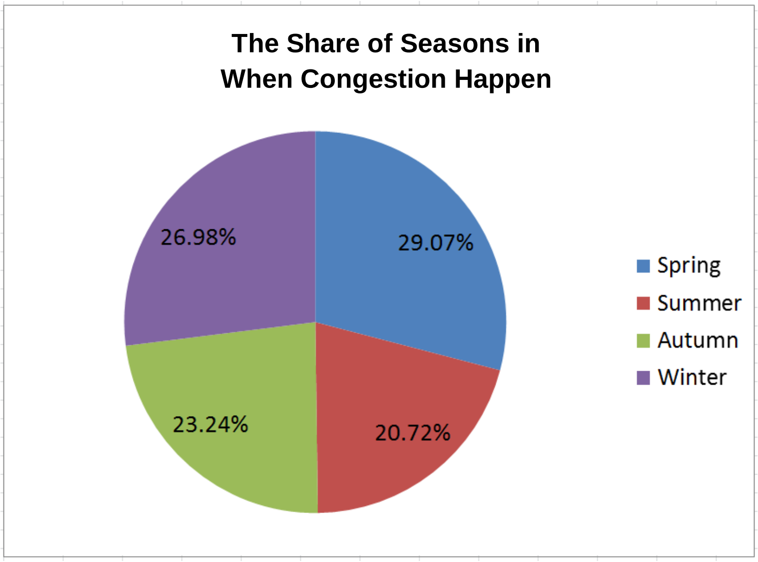


Figure A-4 Share of Seasons in When Congestion Happen

Figure A-6 presents the share of workdays/weekends in when transmission congestions occur. Weekends contribute to a bigger share (31.73%) than the situation if transmission congestions were evenly allocated among different days in a week (2/7*100=28.57%). Therefore, when introducing the time-specific feature to transmission charges, the influence of workdays/weekends should not be ignored as the demand profiles in workdays and weekends are largely different.

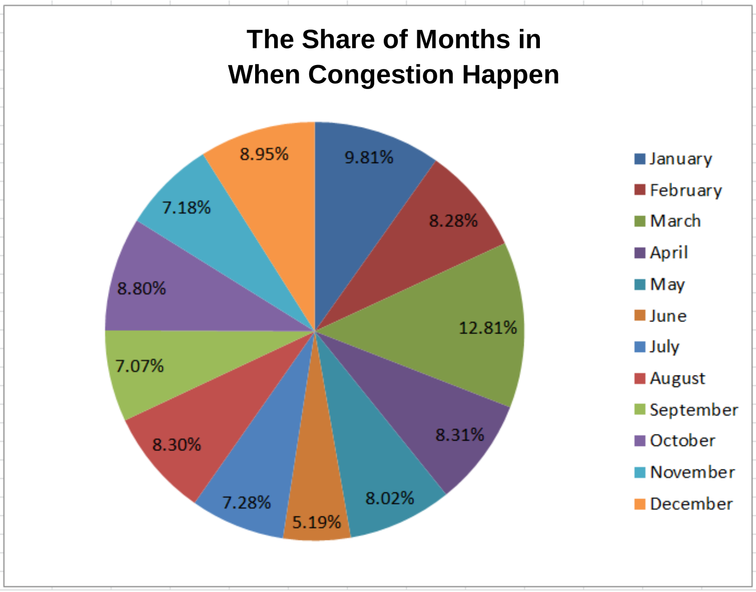


Figure A-5 Share of Months in When Congestion Happen

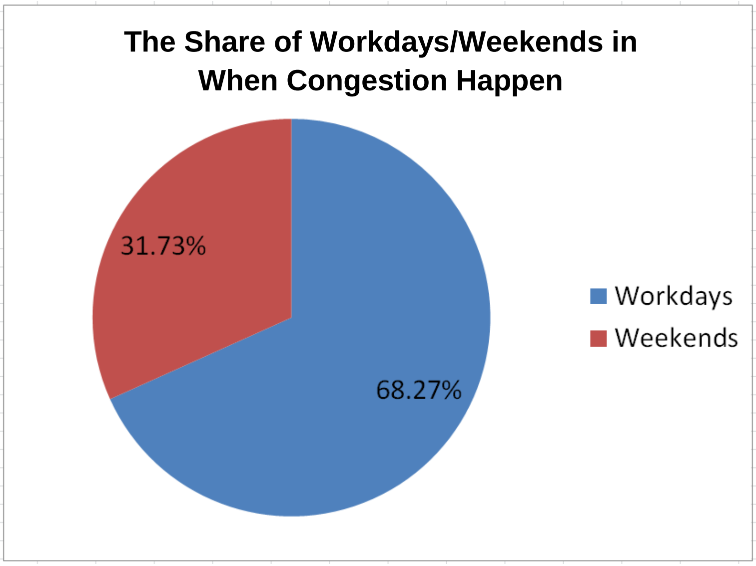


Figure A-6 Share of Workdays/Weekends in When Congestion Happen

The temporal distribution of transmission congestions in seasons, workday/weekends, and along the 24 hours in a day share a lot of similarities with the existing demand profile templates [123]. This comes from the fact that demand varying is still the main driver for time-varying congestion costs in power systems with not too much renewable generation.

A-5 Demonstration Results in Chapter 4

1. Investment Time Horizon

Without capacity changes from any network user, the investment time horizons for B_2-B_4 and B_7 are 15.62, 19.90, 21.56 and 15.78 years respectively. Table A-3 gives the investment time horizons of B_2- B_4 and B_7, if an incremental capacity (1MW) is added to the capacity of generator G_1-G_8. (Dimension: year)

Table A-3 Investment Time Horizon for Incremental Change from Generation

	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8
Branch 2	13.29	13.47	14.89	16.14	15.66	15.18	15.86	16.6
Branch 3	21.65	21.65	20.18	19.69	20.03	20.03	21.16	20.3
Branch 4	21.56	21.56	21.56	21.15	21.51	21.51	21.9	22.21
Branch 7	14.21	14.21	15.54	15.54	15.54	15.54	16.32	16.84

Table A-4 gives the investment time horizons of B_2- B_4 and B_7, if an incremental demand (1MW) is added to the annul peak of demands at nodes $N_1 – N_6$ and N_9 - N_{14}.

Table A-4 Investment Time Horizon for Incremental Change from Demand

	D_1	D_2	D_3	D_4	D_5	D_6
Branch 2	16.86	15.45	15.45	14.68	14.05	14.2
Branch 3	19.95	20.17	18.38	19.67	19.95	19.95
Branch 4	21.58	21.8	20.97	20.35	20.75	20.75
Branch 7	16.52	16.52	14.64	13.44	18.03	16.79
	D_9	D_{10}	D_{11}	D_{12}	D_{13}	D_{14}
Branch 2	14.45	14.45	14.45	14.23	14.23	14.23
Branch 3	19.77	19.77	19.77	19.77	19.77	19.77
Branch 4	20.48	20.48	20.48	20.48	20.48	20.48
Branch 7	14.79	14.79	15.93	16.61	16.61	15.54

2. TUoS Charges for Generators at other nodes

Figure A-7, Figure A-8 and Figure A-9 present the TUoS charges from B_2- B_4 and B_7 for generators connected at node N_2, N_3, and N_4.

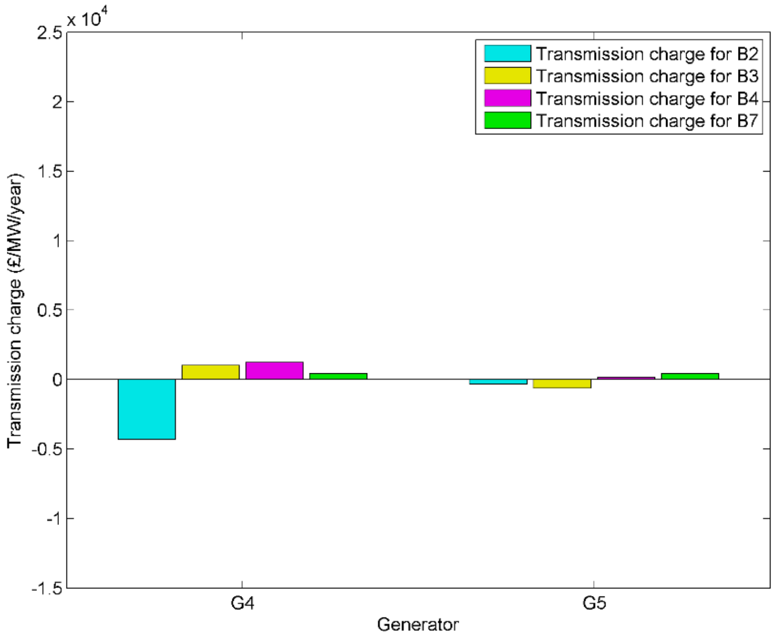


Figure A-7 TUoS Charges for Generators at Node 2

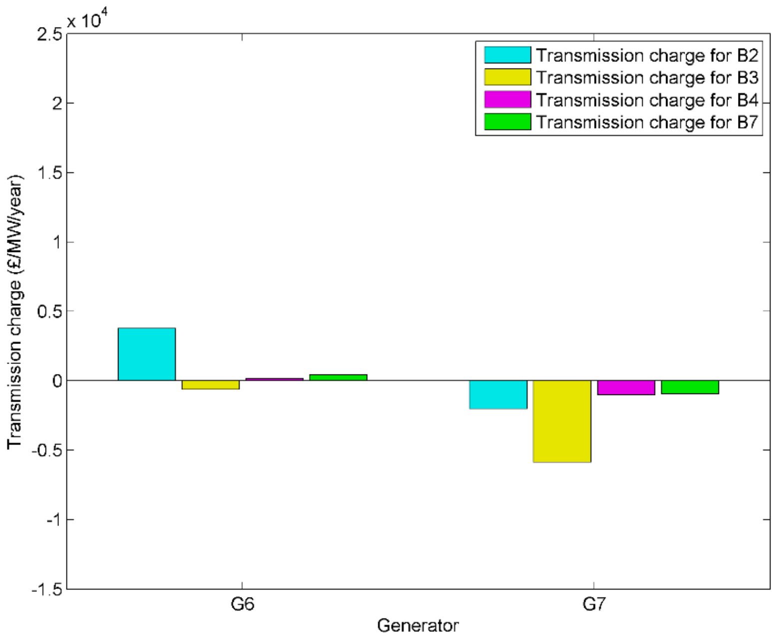


Figure A-8 TUoS Charges for Generators at Node 3

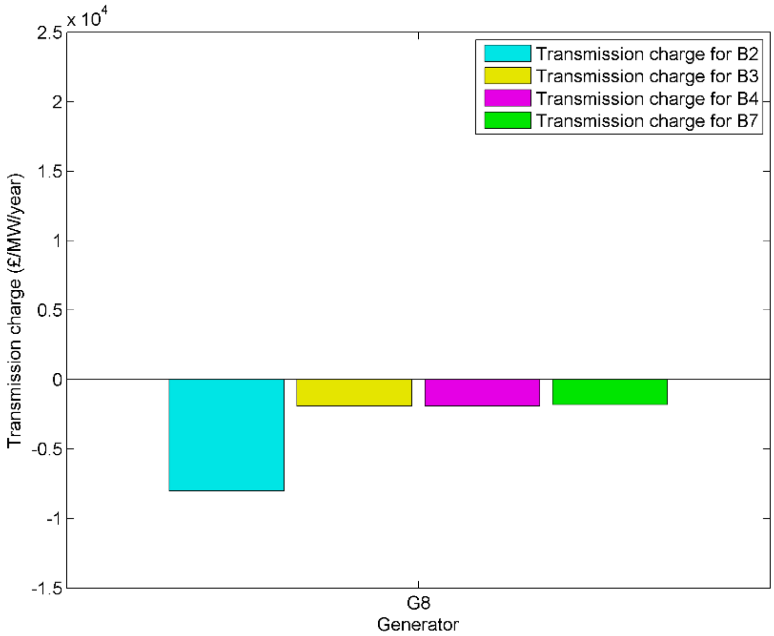


Figure A-9 TUoS Charges for Generators at Node 4

Table A-5 gives the TUoS charges for generators by employing the proposed method. (Dimension: £/MW/year)

Table A-5 TUoS Charges for Generation

	G_1	G_2	G_3	G_4	G_5	G_6	G_7	G_8
Branch 2	21281	19516	6315	-4314	-337	3769	-2010	-8008
Branch 3	-8011	-8011	-1345	1026	-628	-628	-5862	-1914
Branch 4	0	0	0	1245	150	150	-1007	-1905
Branch 7	2903	2903	424	424	424	424	-930	-1795
Total	16173	14408	5394	-1620	-391	3716	-9809	-13623

Table A-6 gives the TUoS charges for demands by employing the proposed method. (Dimension: £/MW/year)

Table A-6 TUoS Charges for Demand

	D_1	D_2	D_3	D_4	D_5	D_6
Branch 2	-9373	2117	2117	8863	14646	13247
Branch 3	0	-1056	8001	1366	0	0
Branch 4	0	-653	1862	3834	2552	2552
Branch 7	-1267	-1267	2078	4443	-3665	-1713
Total	-10639	-859	14058	18505	13533	14086
	D_9	D_{10}	D_{11}	D_{12}	D_{13}	D_{14}
Branch 2	10946	10946	10946	12969	12969	12969
Branch 3	875	875	875	875	875	875
Branch 4	3413	3413	3413	3413	3413	3413
Branch 7	1795	1795	-262	-1416	-1416	424
Total	17030	17030	14973	15841	15841	17682

3. Comparison for Demand TUoS Charges

Figure A-10 compares the TUoS charges for demand under the proposed method and the existing ICRP method.

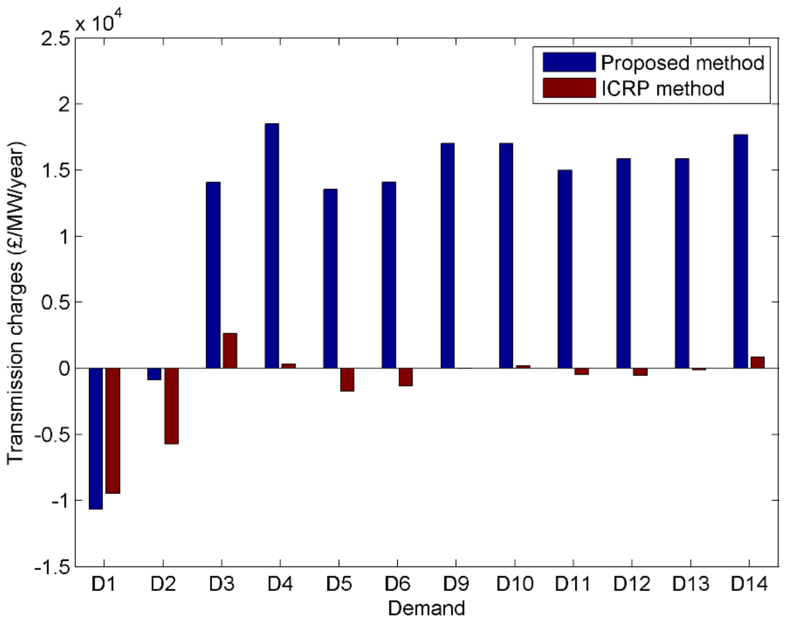


Figure A-10 Comparing Demand TUoS Charges with ICRP Method

Table A-7 gives the TUoS charges for generation and demand under the existing ICRP method. (Dimension: £/MW/year)

Table A-7 TUoS Charges under ICRP method

	N_1	N_2	N_3	N_4	N_5	N_6
Generation	9677	5959	-2417	-115	1967	1554
Demand	-9452	-5734	2642	340	-1742	-1329
	N_9	N_{10}	N_{11}	N_{12}	N_{13}	N_{14}
Generation	235	193	675	792	337	-620
Demand	-10	193	-450	-567	-112	845

TUoS charges gained from the proposed method and the existing ICRP methods are only the initial charges. They would be adjusted to ensure the fixed revenue split from generation and demand (current 27:73). And residual charges would also be added to guarantee the full recovery of allowed revenue. However, these are the out of the scope of this research work. (Detailed introductions are given in section 2.2.2.2).

A-6 Demonstration Results in Chapter 5

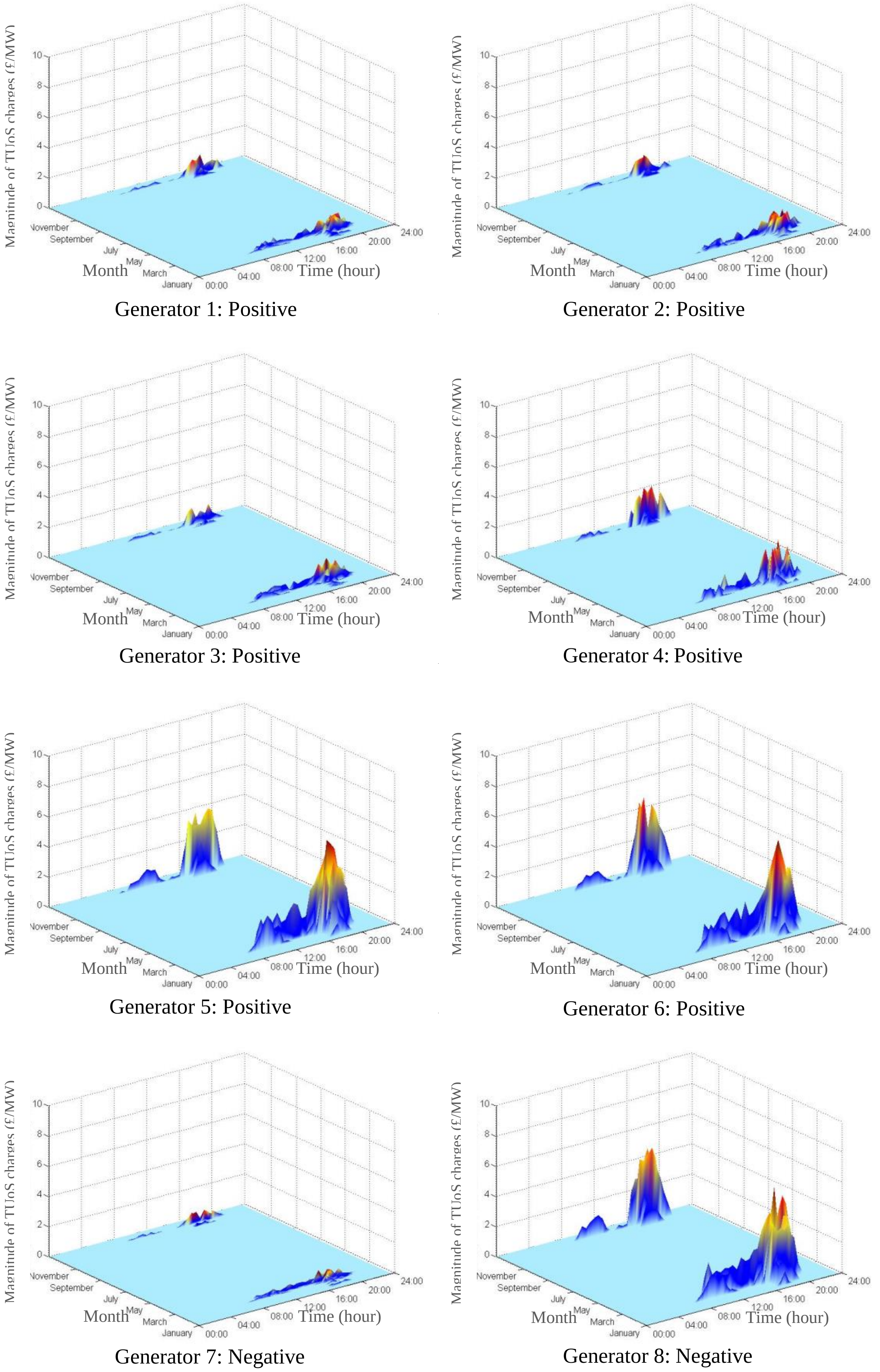
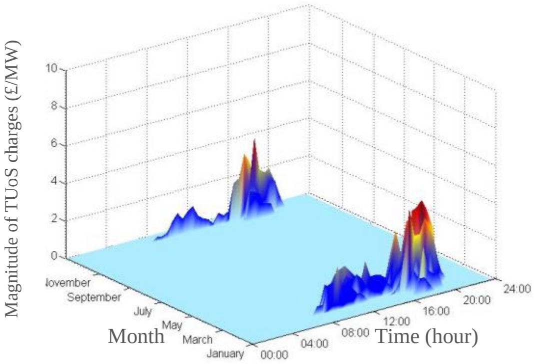
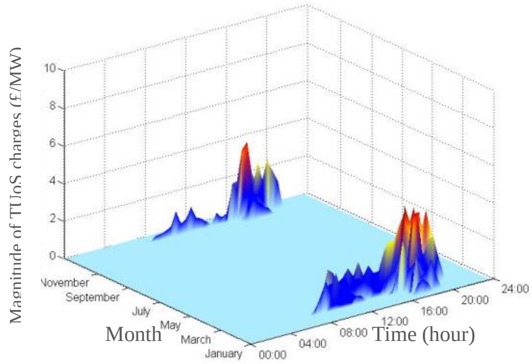


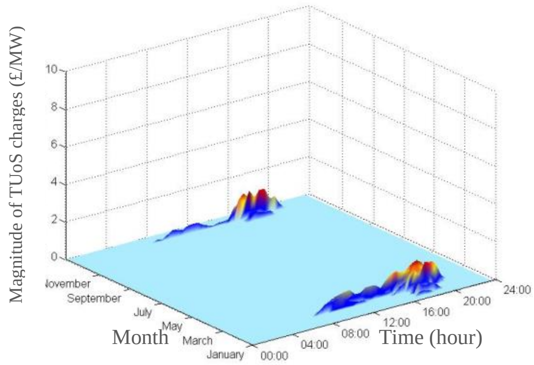
Figure A-11 Time-series TUoS Charges from B_4 for Generators



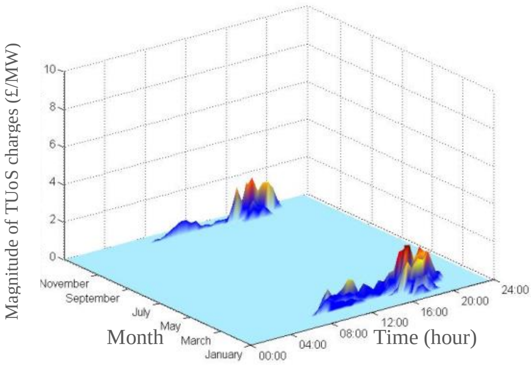
Generator 1: Positive



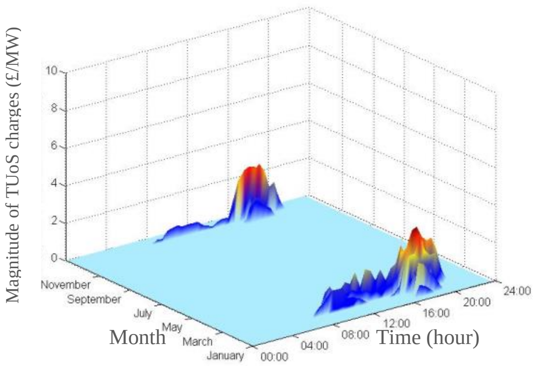
Generator 2: Positive



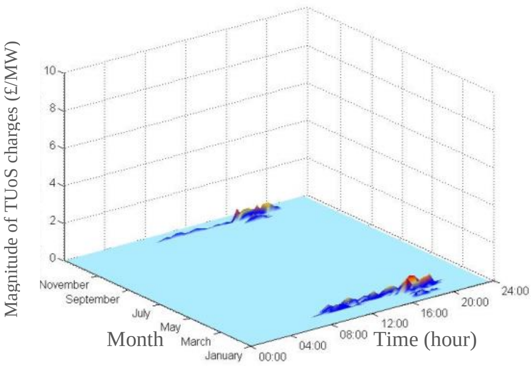
Generator 3: Positive



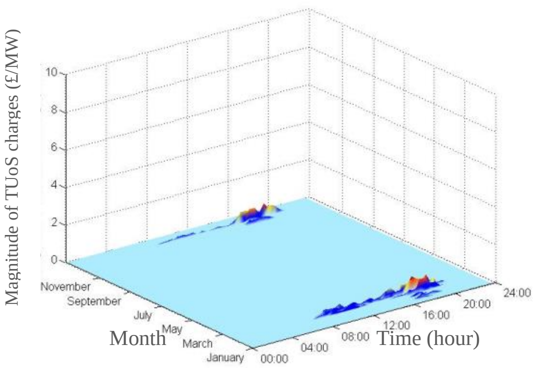
Generator 4: Positive



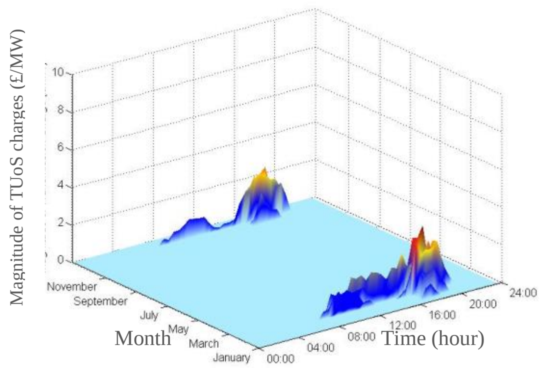
Generator 5: Positive



Generator 6: Positive



Generator 7: Negative



Generator 8: Negative

Figure A-12 Time-series TUoS Charges from B_7 for Generators

(Please note the maximum value of vertical axis is £10/MW per time period)

Table A-8 Time-of-Use TUoS Charges for Winter Workday and Weekend

		Winter Workday			*Winter Weekend*	
		Low Period	***Medium Period***	***High Period***	***Low Period***	***High Period***
G_1	Time Span	00:00-09:30 21:00-00:00	09:30-16:30 20:30-21:00	16:30-20:30	00:00-17:30 19:30-00:00	17:30-19:30
	Charges (£/MW)	0.05	2.50	15.80	0.04	0.37
G_2	Time Span	00:00-09:30 21:00-00:00	09:30-16:30 20:30-21:00	16:30-20:30	00:00-17:30 19:30-00:00	17:30-19:30
	Charges (£/MW)	0.04	2.06	13.46	0.04	0.28
G_3	Time Span	00:00-09:30 21:00-00:00	09:30-16:30 20:30-21:00	16:30-20:30	00:00-17:30 19:30-00:00	17:30-19:30
	Charges (£/MW)	0.03	0.85	5.11	0	0.16
G_4	Time Span	00:00-09:30 21:00-00:00	09:30-16:30 20:30-21:00	16:30-20:30	00:00-17:30 19:30-00:00	17:30-19:30
	Charges (£/MW)	-0.02	-0.47	-2.58	-0.01	-0.13
G_5	Time Span	00:00-08:00 22:00-00:00	08:00-16:30 20:00-22:00	16:30-20:00	00:00-17:30 20:30-00:00	17:30-20:30
	Charges (£/MW)	-0.02	-1.30	-3.81	-0.01	-1.01
G_6	Time Span	00:00-09:30 21:00-00:00	09:30-17:30 20:00-21:00	17:30-20:00	00:00-17:30 20:00-00:00	17:30-20:00
	Charges (£/MW)	0.01	0.68	3.68	0.01	0.11
G_7	Time Span	00:00-09:30 21:00-00:00	09:30-21:00	-	00:00-17:30 20:00-00:00	17:30-20:00
	Charges (£/MW)	-0.02	-0.51	-	-0.01	-0.14
G_8	Time Span	00:00-08:00 21:30-00:00	08:00-16:30 20:30-21:30	16:30-20:30	00:00-17:30 19:30-00:00	17:30-19:30
	Charges (£/MW)	-0.01	-1.42	-7.32	-0.01	-0.75

A-7 Demonstration Results in Chapter 6

Table A-9 gives the Time-of-Use periods and corresponding TUoS charges for all generators in the typical day of winter workday.

In the proposed method, the Time-of-Use periods are specific for each node. However for the generators connected at the same location, their TUoS charges are different.

Table A-9 Time-of-Use TUoS Charges for Winter Workday

Node	*Generator*		*Low Period*	*Medium Period*	*High Period*
N_1		Time Span	00:00-07:30 22:30-00:00	07:30-16:30 20:30-22:30	16:30-20:30
	G_1	Charges (£/MW)	0.02	0.82	1.99
	G_2	Charges (£/MW)	0.02	0.77	1.79
	G_3	Charges (£/MW)	0.02	0.62	1.42
N_2		Time Span	00:00-07:30 22:30-00:00	07:30-16:30 20:00-22:30	16:30-20:00
	G_4	Charges (£/MW)	0.00	0.20	0.78
	G_5	Charges (£/MW)	0.00	0.46	1.45
N_3		Time Span	00:00-08:00 21:30-00:00	08:00-15:30 20:30-21:30	15:30-20:30
	G_6	Charges (£/MW)	-0.01	-1.32	-3.49
	G_7	Charges (£/MW)	0.00	-3.45	-9.14
N_4		Time Span	00:00-10:00 21:30-00:00	10:00-17:30 19:30-21:30	17:30-19:30
	G_8	Charges (£/MW)	-0.01	-0.13	-0.15

Table A-10 gives the Time-of-Use periods and corresponding TUoS charges for all generators in the typical day of winter weekend.

Table A-10 Time-of-Use TUoS Charges for Winter Weekend

Node	***Generator***		***Low Period***	***Medium Period***	***High Period***
N_1		Time Span	00:00-09:30 22:00-00:00	09:30-17:00 20:00-22:00	17:00-20:00
	G_1	Charges (£/MW)	0.00	0.24	0.73
	G_2	Charges (£/MW)	0.00	0.24	0.70
	G_3	Charges (£/MW)	0.00	0.22	0.55
N_2		Time Span	00:00-09:30 22:30-00:00	09:30-17:00 19:30-22:30	17:00-19:30
	G_4	Charges (£/MW)	0.00	0.16	0.24
	G_5	Charges (£/MW)	0.00	0.18	0.59
N_3		Time Span	00:00-11:30 21:30-00:00	11:00-17:00 19:30-21:30	17:00-19:30
	G_6	Charges (£/MW)	-0.01	-0.10	-0.57
	G_7	Charges (£/MW)	-0.01	-0.40	-1.69
N_4		Time Span	00:00-11:00 22:00-00:00	11:00-16:00 21:30-22:00	16:00-21:30
	G_8	Charges (£/MW)	-0.01	-0.05	-0.12

Publications

[1] **Jiangtao Li**; Ran Li; Chenghong Gu; Rohit Bhakar; Furong Li, “A Time-of-Use Transmisison Use of System Charging Methodology” (submitted to *IEEE Transactions on Power Systems*)

[2] **Jiangtao Li**; Chenghong Gu; Rohit Bhakar; Furong Li, “Transmisison Use of System Charging for Differentiating Long-term Impacts from Various Generation Technologies” (revised and re-submitted to *IEEE Transactions on Power Systems*)

[3] **Jiangtao Li**; Zhipeng Zhang; Chenghong Gu; Furong Li, "Long-run incremental pricing based transmission charging method distinguishing demand and generation technologies," *PES General Meeting | Conference & Exposition, 2014 IEEE* , vol., no., pp.1,5, 27-31 July 2014

[4] Furong Li, **Jiangtao Li** and David Tolley. "Year-around System Congestion Cost -Key Drivers and Key Driving Condition," [Online]. Available: https://www.ofgem.gov.uk/ofgem-publications/85136/consultationresponse fromcentrica3.pdf

[5] **Jiangtao Li**; Lin Zhou; Furong Li, "Statistical Probability Based Transmission Congestion Cost Increasing Tendency Analysis," *Power Engineering Conference (UPEC), 2013 48th International Universities'* , vol., no., pp.1,6, 2-5 Sept. 2013

[6] **Jiangtao Li**; Chenchen Yuan; Zhanghua Zheng; Furong Li, "Load factor based transmission network pricing: An evaluation for the improved ICRP method," *Power Engineering Conference (UPEC), 2013 48th International Universities'* , vol., no., pp.1,6, 2-5 Sept. 2013

[7] **Jiangtao Li**; Furong Li; Guy Liu, “A Literature Review on Electricity Transmission Pricing and the Implications to China,” *Chinese Economic Association (UK/Europe) Annual Conference, 2013 24th*, vol., no., pp.1,11, 30-31. Aug 2013

[8] **Jiangtao Li**; Chenchen Yuan; Furong Li, "The relationship of constraints cost and load factor: A evaluation for the improved ICRP method," *European Energy Market (EEM), 2013 10th International Conference on the* , vol., no., pp.1,8, 27-31 May 2013

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[10] Zhipeng Zhang; **Jiangtao Li**; Furong Li; Budd, C.; Hamidi, V., "Assessment of DG security contribution on transmission levels," *PES General Meeting | Conference & Exposition*, 2014 IEEE , vol., no., pp.1,5, 27-31 July 2014

[11] Fan Yi; Pingliang Zeng; Shuang Yu; Chenghong Gu; **Jiangtao Li**; Chenchen Yuan; Furong Li, "Impacts of classified electric vehicle charging derived from driving patterns to the LV distribution network," *PES General Meeting | Conference & Exposition, 2014 IEEE* , vol., no., pp.1,5, 27-31 July 2014

Long-Run Incremental Pricing based Transmission Charging Method distinguishing Demand and Generation Technologies

Jiangtao Li, Zhipeng Zhang, Chenghong Gu and Furong Li
Department of Electronic & Electrical Engineering
University of Bath
Bath, United Kingdom
J.Li@bath.ac.uk, Z.Zhang2@bath.ac.uk, C.Gu@bath.ac.uk, F.Li@bath.ac.uk

***Abstract*— This paper develops a novel transmission charging method based on long-run incremental cost (LRIC) pricing. It is able to recognize the trade-offs between short-run congestion cost and future investment cost. Innovatively, it can differentiate the impact of demand and generation technologies on advancing or deferring network investment. An incremental capacity change from a network user influences congestion cost first, which is then converted into network investment horizon. The difference in the present values with and without the incremental change is the long-run incremental cost (LRIC), which is the transmission tariff for this network user. The demonstration results illustrate that the proposed approach provides positive tariffs for congestion contributors (charges) and negative tariffs for congestion eliminators (rewards) in congestion areas. It offers distinguishing tariffs for different generation technologies and updates the tariffs to reflect the changes in generation mix. The proposed approach can incentive appropriate generation behavior to reduce congestion cost and ultimately network investment cost.**

***Index Terms*-- Congestion Management, Long-Run Incremental Cost, Transmission Investment, Transmission Pricing, Transmission Use of System Charges.**

I. INTRODUCTION

Due to the continuous demand growth and largely deployment of renewable generation, congestion occurs more frequently in transmission networks as a result of insufficient network capacity. To avoid power line overloads, operational measures like generation re-dispatch are employed in short-run congestion management [1]. These measures can not only improve the efficiency of existing transmission networks, but also defer the costly network investment. The short-run congestion management imposes a significant influence on long-run transmission network investment decisions.

Transmission Use of System (TUoS) charges are designed against all transmission network users to recover the costs of network maintenance and investment. Another important function of TUoS charges is to provide forward-looking, economically efficient signals for both existing and new power companies/ consumers to influence them to decide where/when to consume/produce electricity in the short-run and where/when to connect demand/build generation in the long-run [2].

Investment cost related pricing (ICRP) method is one of the most advanced TUoS charging methodologies. It derives locational tariffs representing the cost of providing transmission capacity as a result of an incremental generation or demand at the time of system peak [3]. An improved ICRP (IICRP) method has been proposed under Project TransmiT launched by Ofgem to address the trade-off between short-run congestion cost and long-run investment cost [4, 5]. IICRP realizes that different generators contribute to contribute to congestion distinctly thus require different transmission capacities. It employs specific generator annual load factor to distinguish different generation technologies. University of Bath undertook in-depth review for IICRP method and declared the concerns that the distinct characteristics of different generation technologies are not properly represented via generator load factor [6, 7].

Long-run incremental cost (LRIC) pricing method derive forward-looking, locational economic signals to reflect the impact of demand/generation on network investment horizon [8]. It was first applied into distribution network use of system charging [9]. This paper innovatively develops a transmission charging method based LRIC pricing, which recognizes increasing annual congestion cost as the trigger of transmission network investment. The innovative contribution is to derive distinguishing TUoS charges for demand and different generation technologies as their influence on the present value of future network investment due to incremental capacity change. The proposed approach resolves the disadvantages of the IICRP method.

The rest of the paper is organized as follows: Section II shows the compact but revolutionary process to extend LRIC pricing method to TUoS charging. In Section III, how to distinguish demand and different generation technologies is explained. Section IV employs a simple system to demonstrate the efficiency of the proposed approach. Finally, conclusions and future works are drawn in Section V.

II. LRIC Pricing Method for Transmission Use of System Charges

A. The trigger of tranmission network investment

A general generation dispatch is modeled as:

$$Min\ \sum_{i,j} C_{ij}\left(P_{G_{ij}}\right) = \sum_{i,j}(a_{ij}P_{G_{ij}}^2 + b_{ij}P_{G_{ij}} + c_{ij}). \quad (1a)$$

subject to

$$\sum_{i,l} P_{il} + P_{D_i} = \sum_{i,j} P_{G_{ij}}. \quad \text{for all bus i} \quad (1b)$$

$$P_{G_{ij}}^{min} \leq P_{G_{ij}} \leq P_{G_{ij}}^{max}. \quad \text{for all generators } G_{ij} \quad (1c)$$

$$|P_{il}| \leq P_{il}^{max}. \quad \text{for all power line } L_{il} \quad (1d)$$

where C_{ij} is the cost function of generator j at bus i, a_{ij}, b_{ij} and c_{ij} are the cost function coefficients, P_{Gij} is the generation output; (1b) represent the power balance at bus i (network losses are ignored); (1c) represents generation capacity limits; (1d) represents power line transmission capacity limits.

In this paper, congestion cost is defined as the increase in generation cost due to the inclusion of power line transmission capacity limits [1].

Congestion cost (CC) is

$$CC = \{Min\ C|1a - 1d\} - \{Min\ C|1a - 1c\}. \quad (2)$$

Congestion occurs when power flow reaches the power line maximum capacity. t_l is assumed to be the period before congestion happening. It is at this time that network investment is unavoidable for distribution network, where the trigger of network investment is the demand growth and network spare capacity. In transmission network, investment decisions are made upon the trade-off between short-run congestion cost and long-run investment cost. The trigger of transmission network investment is the increasing of congestion cost. Congestion management is a better alternative solution until the annual congestion cost exceeds the annualized network investment cost. It is assumed that this situation last for a period of t_c. The solid lines in Fig. 1 are drawn to explain this relationship.

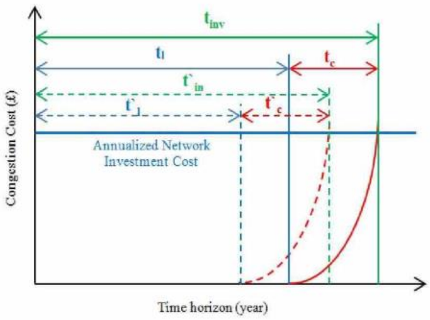

Figure 1. Time horizon of transmission network investment

The time horizon of transmission network investment (t_{inv}) is the year when the present value of annual congestion cost (ACC) of year t_{inv} equals to or exceeds the present value of annualized investment cost (AIC). This relationship is:

$$t_{inv} = t_l + t_c. \quad \text{when ACC} \geq \text{AIC} \quad (3a)$$

B. LRIC based TUoS charging method

The LRIC based TUoS charging method employs a similar philosophy as the LRIC based charging method for distribution network [9].

Given a fixed discount rate d, the present values of annualized investment cost ($PAIC_l^{t_{inv}}$)) and annual congestion cost ($PACC_l^{t_{inv}}$) for power line l in year t_{inv} are

$$AIC_l = \frac{Assert\_cost_l}{Annuity\ Factor}. \quad (4)$$

$$PAIC_l^{t_{inv}} = \frac{AIC_l}{(1+d)^{t_{inv}}}. \quad (4a)$$

$$PACC_l^{t_{inv}} = \frac{CC_l^{t_{inv}}}{(1+d)^{t_{inv}}}. \quad (4b)$$

where $Assert\_cost_l$ is the modern equivalent value for the investment value for power line l; the calculation of *Annuity Factor* is explained in Appendix; $CC_l^{t_{inv}}$ is the annual congestion cost for power line l in year t_{inv}.

An incremental change in demand or generation (Δ) causes an increase/decrease in annual congestion cost. The future network investment will be advanced or deferred from year t_{inv} to year $t`_{inv}$, as shown by the dashed lines in Fig. 1. The relationship is

$$t`_{inv} = t`_l + t`_c. \quad \text{when ACC} \geq \text{APV} \quad (3b)$$

This also change the present value of annualized investment cost and annual congestion cost to $PAIC`_l^{t_{inv}}$ and $PACC`_l^{t_{inv}}$, respectively.

$$PAIC`_l^{t_{inv}} = \frac{AIC_l}{(1+d)^{t`_{inv}}}. \quad (4c)$$

$$PACC`_l^{t_{inv}} = \frac{CC_l^{t`_{inv}}}{(1+d)^{t`_{inv}}}. \quad (4d)$$

The long-run increment cost for the minor change Δ is

$$\begin{aligned} \text{LRIC}_l(\Delta) &= PAIC`_l^{t_{inv}} - PAIC_l^{t_{inv}} \\ &= AIC_l\left(\frac{1}{(1+d)^{t`_{inv}}} - \frac{1}{(1+d)^{t_{inv}}}\right). \quad (5) \end{aligned}$$

Equations (3)-(5) are the core procedure for LRIC based TUoS charging method.

For a specific demand or generator, its TUoS tariff is the summation of long-run incremental costs over all supporting asserts.

III. Distinguishiing Charges for Load and Different Generation Technologies

The trigger of transmission network investment---annual congestion cost, is shaped by many system parameters from demand side, network side and generation side. In this paper, only demand driven congestion is considered, in which congestion occurs mainly due to demand growth.

A. The composition of congestion cost

The schematic diagram in Fig. 2 is used to explain the occurrence of transmission congestion and investigate the various influences of demand and different generation technologies on congestion cost.

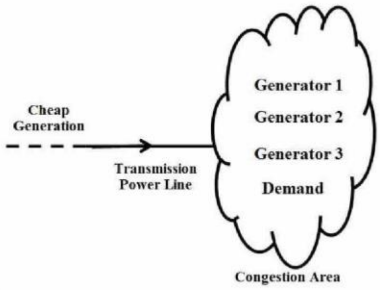

Figure 2. Schematic diagram for transmission congestion

Without the inclusion of transmission capacity limits, the total demand is met by cheap generation from far away via transmission power lines. Thus, the total generation cost achieved to be the minimum. If the transmission capacity limits are taken into account, partial demand above transmission capacity might have to be met by the relatively expensive generation in the congested areas. The increment in generation cost is congestion cost.

In power systems, different generation technologies, such as nuclear, coal, gas and wind, are mainly recognized by their generation cost functions and availability [10]. In this paper, only conventional generation technologies are considered. The cost functions for each generation technologies are assumed to be linear for simplification and expressed as $P_{G_C}, P_{G_1}, P_{G_2}, P_{G_3}$. The installed capacity for each generation technologies are accumulated and expressed as $C_{G_C}, C_{G_1}, C_{G_2}, C_{G_3}$.

B. TUoS charges for dmeand and different generation technologies

Different generation technologies have various roles in meeting varying demands over time and use the transmission network at diverse degrees. Therefore, they should pay distinguishing TUoS charges.

To calculate annual congestion cost in a future year t_{inv}, the demand is recognized to follow a continuous growth rate

$$D_{inv} = D_{ini} \times (1 + r)^{t_{inv}} \qquad (6)$$

where r is the demand growth rate per year, D_{ini} is the initial demand, D_{inv} is the demand at year t_{inv}. As the LRIC charging method is applied to guide the siting and sizing of future generation and demand under existing transmission infrastructure, the future generation and transmission expansions are not considered in deriving tariffs.

The LRIC based TUoS charges for demand and different generation technologies are designed based on the following philosophy, summarized in Table I.

- *Demand*: Demand in the congestion area losses profit from congestion as it pays higher electricity prices under congestion and benefits from network investment. Incremental increase in demand causes the growth in congestion cost thus advances the transmission investment (from t_{inv} to $t`_{inv}$). Therefore, the demand should be charged through TUoS tariff.
- *Generator G_1 and G_2*: G_1 and G_2 represent the base and fossil fuel-fired generation in the congestion area, which contribute to the vast majority of congestion cost. They benefit from congestion, as they are re-dispatched to meet demand under congestion situation. An incremental growth in generation capacity C_{G1} / C_{G2} reduces the annual congestion cost through replacing expensive electricity from G_3 with a relatively cheaper one thus defer the transmission investment. Therefore, the TUoS tariff should reward these generation in congested area.
- *Marginal generator G_3:* G_3 represent the peaking generation in the congestion area, which contributes little share to the congestion cost. It also benefits under congestion and loses profit if investment is conducted. However, it is not feasible to calculate the LRIC based TUoS tariff for G_3 in a similar way as G_1 and G_2, since its capacity is not fully utilized and an incremental change from C_{G3} has no influence on annual congestion cost. The LRIC based TUoS tariff for G_3 is zero, which reflects the real economic meaning of LRIC charging method. G_3 indeed plays an essential role in maintaining the system capacity margin and providing secure electricity supply. It is rewarded by the high electricity prices in energy market and the payment from capacity market. However, these are out of the scope of this paper and not investigated here.

TABLE I. TUoS CHARGING PHILOSOPHY

	Influence under congestion	Influence by investment	Influence on CC due to unit Δ	Influence on investment time due to unit Δ	LRIC TUoS Tariff (+/-)
D	Lose profit	Benefit	Increase	Advance	Charge(+)
G_1	Benefit	Lose profit	Decrease	Defer	Reward(-)
G_2	Benefit	Lose profit	Decrease	Defer	Reward(-)
G_3	Benefit	Lose profit	N.A (0)	N.A	N.A (0)

IV. DEMONSTRATION & DISCUSSION

The demonstration system employed in this paper is the simple power system in Fig. 2. Six scenarios of generation mix in demand center, as shown in Table II, are applied to verify the efficiency of the proposed LRIC based TUoS charging approach.

The peak demand at year t=0 is 100MW. This demand profile follows the data from IEEE Reliability Test System 1996 [11]. The demand growth rate is 2.2% per year. The year-round demands increase proportionally so that the demand characteristics are kept.

TABLE II. SYSTEM PARAMTERS UNDER SIX SCENARIOS

Scenario	G_1		G_2		G_3	
	Price (£/MWh)	*Capacity (MW)*	*Price (£/MWh)*	*Capacity (MW)*	*Price (£/MWh)*	*Capacity (MW)*
A1	15	10	30	20	50	50
A2	15	20	30	10	50	50
A3	15	20	30	20	50	50
B1	12	10	30	20	50	50
B2	12	20	30	10	50	50
B3	12	20	30	20	50	50

The power line transmission capacity is set as 100 MW. Its modern equivalent value is £10,169,420. The discount rate is 6.9% per annual. The assets life span is 45 years. With the Annuity Factor explained in Appendix, the annualized investment cost is £738,520.

Scenarios A1-A3 assume that P_{GC} (£12 MWh) is lower than P_{G1}, P_{G2} and P_{G3}. Scenarios B1-B3 assume that P_{GC} (£15 MWh) is higher than P_{G1} (£12 MWh) but lower than P_{G2} and P_{G3}, which is more close to the real situation. The difference between scenarios A1-A3 (also scenario B1-B3) is the change of C_{G1} and C_{G2}. C_{G3} is set as 50MW, which makes generation expansion unnecessary before network investment.

TABLE III. INVESTMENT TIME UNDERSIX SCENARIOS

Scenario	t_{inv} initial (year)	$t`_{inv}$ for D (year)	$t`_{inv}$ for G_1 (year)	$t`_{inv}$ for G_2 (year)	$t`_{inv}$ for G_3 (year)
A1	20.15	19.69	20.45	20.22	20.15
A2	22.09	21.63	22.36	22.20	22.09
A3	22.96	22.50	23.22	23.01	22.96
B1	21.43	20.98	21.79	21.54	21.43
B2	23.58	23.13	23.92	23.73	23.58
B3	24.86	24.40	25.19	24.96	24.86

Table III gives the initial time horizon of network investment and $t`_{inv}$ due to an incremental change of D, G_1, G_2 and G_3 respectively under each scenario.

Fig. 3 depicts the time horizon of network investment in bar chart. It tells that the incremental increase of demand in the congestion area advance the transmission investment but the incremental increase of generation in the congestion area defers the transmission investment. As G_1's generation cost is cheaper, the transmission investment is deferred to a further future when compare to G_2. The incremental increase of C_{G3} doesn't cause the growth of congestion cost so that the time horizon of network investment remains unchanged. Scenarios B1-B3 share similarities with scenarios A1-A3 thus proves the wide adaptability of the proposed approach.

By employing the proposed LRIC based TUoS charging method, Table IV provides the TUoS tariffs for D, G_1-G_3 under six scenarios.

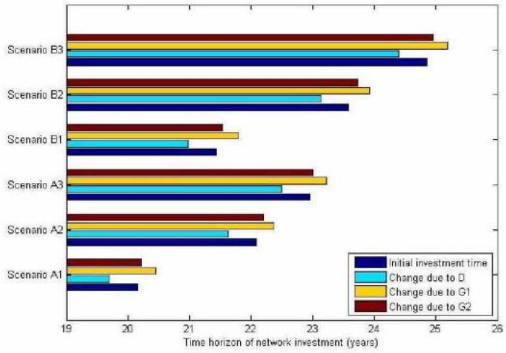

Figure 3. Time horizon of network investment under each scenario

TABLE IV. TUOS TARIFF FOR SIX SCENARIOS

Scenario	TUoS tariff for D (£/MW per year)	TUoS tariff for G_1 (£/MW per year)	TUoS tariff for G_2 (£/MW per year)	TUoS tariff for G_3 (£/MW per year)
A1	5959.88	-3764.38	-845.81	0
A2	5238.00	-3086.936	-1293.14	0
A3	4953.58	-2734.97	-542.29	0
B1	5471.64	-4136.74	-1233.76	0
B2	4740.40	-3384.24	-1514.57	0
B3	4362.60	-3034.21	-934.93	0

Fig. 4 describes the TUoS tariff under each scenario in bar chart. The TUoS tariffs for demand (congestion contributors) are positive, which means that new demand is not welcome in a congestion area. The TUoS tariffs for generation (congestion eliminators) are negative, which means that generation expansion is welcome in a congestion area before network investment. The generation technology for G_1 is more welcome than G_2, which is reflected by a larger absolute charge. The TUoS tariff for G_3 is zero, the reason is provided in section III. The results prove the efficiency of the proposed approach in providing economic charging signals.

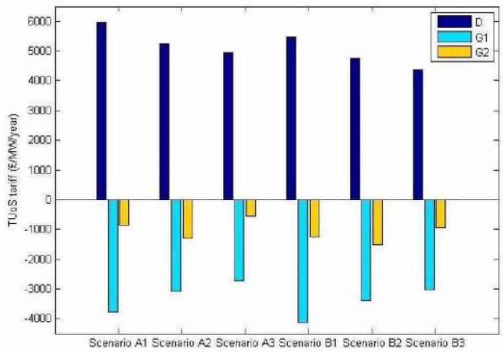

Figure 4. TUoS tariff under each scenario

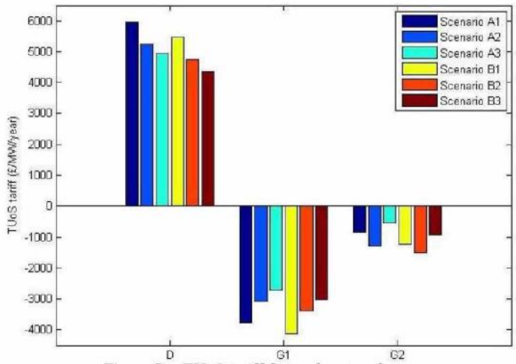

Figure 5. TUoS tariff for each network user

Fig. 5 demonstrates the TUoS tariffs for each network user in bar chart. It shows that demand is paying a smaller tariff from £5960/MW/year to £4954/MW/year with more cheap generation available from scenario A1 to scenario A3. The change from scenario A1 to A2 represents a generation mix change. The TUoS tariff for G_1 decreases but that for G_2 increases. It means that the generation technologies G_1 is less attractive in scenario A2 than in scenario A1 and generation technology G_2 become more welcome. The change from scenario A1 to A3 or from scenario A2 to A3 represents a generation expansion. Both the TUoS tariffs for G_1 and G_2 are reduced. Scenarios B1-B3 share similarities with scenarios A1-A3. These values prove the wide adaptability of the proposed approach. The proposed approach successfully update tariff when the generations mix changes.

V. CONCLUSION AND FUTURE WORK

This paper develops a revolutionary Transmission Use of System (TUoS) charging method based on long-run incremental cost (LRIC) pricing. The proposed LRIC based TUoS charging method recognizes the growth of congestion cost as the trigger of transmission network investment. It reflects the trade-off between short-run congestion cost and long-run investment cost. When annual congestion cost exceeds annualized investment cost, it is time to invest network. An incremental change in demand and generation technologies influences the annual congestion cost first, which is then converted to advancing or deferring the investment horizon. The present value of network investment with and without incremental change is the long-run incremental cost, which is the TUoS tariff for that network user.

The demonstration system employs six scenarios to prove the efficiency and adaptability of proposed approach. The results show that it provides positive tariffs for congestion contributors (charging) and negative tariffs for congestion eliminators (compensating). Innovatively, it offers distinguishing tariffs for different generation technologies and updates the tariffs reflecting the generation mix change. Therefore, the proposed LIRC approach is capable to incentive appropriate generation behavior to reduce congestion cost and ultimately investment cost.

There is no doubt that the proposed method can easily find its application in charging international interconnectors and main boundaries over transmission systems. The future work is to expand the proposed approach by considering the availability of different generation technologies and meshed transmission network topology.

APPENDIX

Annuity factor represents the ratio between a series of regular payments/income and future payment/income, with the reflection of the time value of money. In this paper, it is used to find the annualized investment cost over assert's life span for a future investment, whose cost is known in advance.

The formula to calculate annuity factor is:

$$\text{Annuity Factor} = \frac{1-(1+r)^{-n}}{r}.$$

where r is rate per period, n is the number of periods. For this paper, the annuity factor is 13.77.

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Year-round System Congestion Costs - Key Drivers and Key Driving Conditions

A report to Centrica and RWE

Professor Furong Li
Jiangtao Li
Professor David Tolley

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Executive Summary

Project scope and approach

Centrica and RWE have commissioned the University of Bath to undertake a review of two aspects of the proposals advanced in the CMP213 Working Group consultation of 7th December 2012. These relate to that part of the CMP213 proposals intended to improve the incremental cost signal in the ICRP methodology. Specifically, the University of Bath has been asked to address:

- The use of a generator annual load factor as a proxy for the causation of constraint costs; and
- The use of a dual background for devising the locational signal in TNUoS charges.

In order to address these points the University of Bath has undertaken a series of high-level studies based on a representation of the GB transmission system so as to test the basis for the CMP213 proposals. These studies focus on the key driving factors which determine year-round congestion costs. The studies attempt to answer three fundamental questions that underpin the network sharing concept.

i) Is it appropriate to assume that load factors can be used to represent a generation technology?

ii) Is it appropriate to assume a linear relationship between load factors and congestion costs, so that load factor can be used as a proxy for year-round congestion costs?

iii) Can a dual background realistically reflect the congestion conditions and thus its costs throughout the year?

Conclusions

The University of Bath supports the industry's effort to enhance the TNUoS charging methodology such that it can recognise the impact of differing generation technologies on incremental transmission network cost/congestion cost, particularly in the light of the rising volume of intermittent renewable generation across the system. However, we have serious misgivings over the direction that 'network sharing' takes in the original CMP213 proposals. We believe the approach proposed could seriously compromise the objectives of project TransmiT which are to "*to facilitate the timely move to a low carbon energy sector whilst continuing to provide safe, secure, high quality network services at value for money to existing and future consumers*".

i) Load factor analysis

Our work demonstrates that a generator's load factor is not a fixed parameter, but a highly complex parameter that is shaped by network location, network characteristics (in terms of length, capacity, utilisation, congestion across each interconnected boundaries), characteristics of generation (such as generation mix, efficiency, controllability, cost curves and output variability), characteristics of demand (such as demand duration curves, and demand profiles), the direction and utilisation of interconnectors, as well as market fundamentals. This is an important result because CMP213 uses a fixed load factor assumption to differentiate generation technologies as a key initial input to deriving charges. These are borrowed from the SQSS and then used to allocate circuits as falling into 'year-round' or 'peak' categories.

Our study shows that for the same generation technology but with different efficiencies (price), location, and boundary congestion levels, generators will have very different load factors. Our example shows that an increase in boundary capacity leads to less congestion resulting in lower cost generation being able to transfer more power thus increasing its load factor, whilst the load factor of the more expensive generation reduces. In the simplified network chosen for the study, when the transmission transfer capacity was increased by 25%, the load factor of the cheaper generator increased from 60% to 65%, while the more expensive generator load factor fell from 12% to 5%. The consultation document also observed that as the penetration of intermittent generation increases, the output of conventional generation will change and evolve with it over time.

Annual load factor for a generation technology is a variable that is shaped by differing generator and demand parameters, and features of the transmission system. It is thus inappropriate to use the same load factor for a generation technology regardless of its locations, efficiencies and market behaviour.

ii) The relationship between load factor and year-round congestion costs

When investigating the possible relationships between year-round congestion cost and annual load factor, we have illustrated how a change in wind penetration level, transmission capacity and generation price characteristics might impact load factor and congestion costs. Our studies demonstrated that under different network, generation and demand conditions the relationship between congestion costs and load factor can vary significantly. The relationship most certainly can not be assumed to be linear.

It is thus impossible to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless account is also

taken of other factors such as location, efficiency, market conditions, and critically, the network transfer capability.

iii) The dual background approach

To examine the validity of introducing a dual background approach into charging as proposed by CMP213, we have developed the concept of a congestion duration curve that charts the variation in the magnitude of congestion costs throughout the year. The objective has been to investigate how congestion cost varies in strength and duration, over time and between locations.

Our study is of a system that comprises a representation of the B6 and B15 boundaries; the two GB boundaries with the heaviest congestions. The congestion duration curve in Figure 1 below shows that congestion arises in varying degrees, over different time periods. Table 1 shows that congestion cost is not only linked to the magnitude of congestion, but critically to time, duration and location.

Part 1 of the curve indicates a period of extremely high congestion where costs are in excess of £44k per settlement period. Although of considerable magnitude this high level of cost is incurred for only 23 settlement periods out of a total of 17,520 in the year. The proportion of the total annual congestion cost in this period is thus relatively small (1.1%), and can for all practical purposes be ignored when approximating the year-round congestion cost.

Part 3 of the curve represents the largest share of the year-round congestion costs but still only accounts for 5,427 settlement periods or 31% of the year. The issue in relation to the CMP213 proposals is that in the original proposals the annual load factor is averaged over the course of the year and consequently its use as a proxy for congestion could severely underestimate the congestion costs over the critical congestion periods; and thus significantly dilute the efficacy of the economic signals.

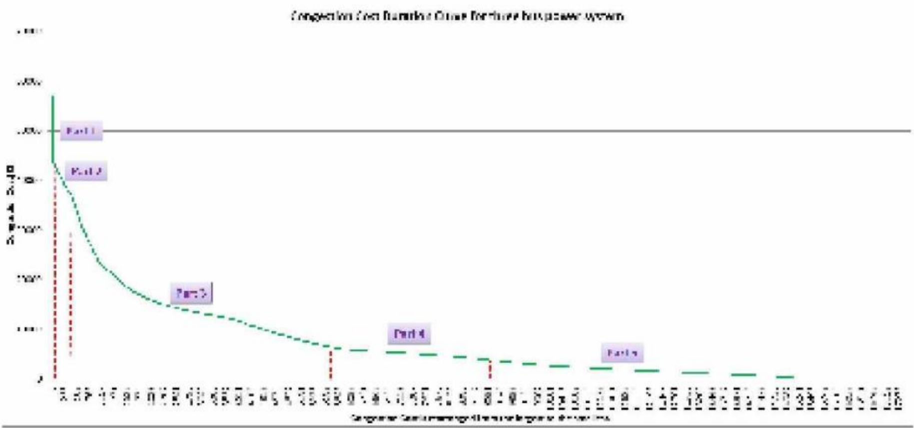

Figure 1: Congestion duration curve.

Table 1: Congestion cost between B6 and B15 for parts of congestion duration curve

	Number of settlement periods	B6 Congestion Cost £M	B15 Congestion Cost £M	Total Congestion Cost £M	Congestion share between different the 5 parts	Proportion of B6 in Total Congestion Cost	Proportion of B15 in Total Congestion Cost
Part 1	23	1.3	0	1,3	1.06%	100.00%	0.00%
Part 2	394	12.0	3.8	15.8	12.87%	75.75%	24.25%
Part 3	5427	67.4	11.3	78.7	63.91%	85.63%	14.37%
Part 4	3042	4.8	10.7	15.5	12.57%	31.44%	68.56%
Part 5	8634	10.9	0.9	11.8	9.58%	92.71%	7.29%
Total	17520	96.5	26.6	123.1	100.0%	78.38%	21.62%

We have also investigated the most significant periods that contribute to the majority of year-round congestion costs, and how the congestion cost is shared between B6 and B15 boundaries. Our study shows that the periods covering parts 2, 3, and 4 of the congestion duration curve shown in Figure 1 account for 94% of system congestion. It is these periods that should be adopted as background scenarios for deriving the year-round congestion costs sine they display both high magnitude and/or long duration.

The study also indicates that congestion costs not only vary over time and duration (different backgrounds), but also vary significantly between boundaries. The B6 boundary is responsible for over 80% of all system congestion, but this congestion does not occur with the same degree or at the same time across as across the B15 boundary. In fact the B6 and B15 boundaries are only congested simultaneously for 14% of the year. Furthermore congestion across B6, when it occurs is significantly higher than across B15. This suggests that congestion cost is sensitive not only to time and duration, but more significantly to the location of the boundary.

These differences of congestion in terms of magnitude, time and location are not reflected in the proposals for an improved ICRP. Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year. The use of annual load factors in a year-round scenario to reflect year-round congestion costs essentially assumes that all boundaries have the same level of congestion throughout the year. It cannot provide an appropriate economic message for reducing congestion, and it certainly will not reflect the costs of congestion in accordance with SLC 5.5b

Summary of Key Findings

- Annual load factor of a generation technology is not a fixed parameter but a variable that changes with generation, network and market conditions. It is thus inappropriate to use it as an input for a generation technology regardless of its location, efficiencies and market behaviour.
- The relationship between load factor and congestion cost most certainly can not be assumed to be linear. Load factor is a measure of an average output of a generation technology over the year; whilst congestion cost is sensitive to time (backgrounds), duration elements and boundary locations. The relationship between load factor and congestion cost varies greatly with transmission transfer capabilities, demand profiles and generation mixes, efficiency, controllability and their locations in the system.
- It is not appropriate to infer that by assuming linearity between load factor and constraint costs the charging methodology will be enhanced; unless it is further amended to take account of other factors, such as location, efficiency, market conditions and critically, network transfer capability.
- Even for a simple representation of the GB transmission system it is necessary to recognise at least five different congestion periods that will reflect the incidence of year round congestion. Within each period there are considerable differences in the timing and sharing of network congestion costs between the two most heavily congested boundaries.
- The single “year-round” condition is flawed in that it does not reflect the difference in magnitude, duration and location of the congestion. Instead the scenario proposed will represent an extremely high congestion condition that lasts for a very limited duration, and contributes little towards overall system congestion costs.
- Employing load factor as a surrogate for the cause of congestion smears the consequence for one boundary across all boundaries and throughout the year, by assuming that all boundaries have the same level of congestion at all times in the year. It cannot provide the necessary economic message for reducing congestion, and it certainly will not reflect the costs of congestion as required by the Licence Conditions.
- Our view is that a consequence of adopting the current CMP 213 proposals for an improved ICRP methodology will be to increase congestion costs, which would be perverse given the objectives of project TransmiT . Our conclusion is that employing only two backgrounds would fail to create even the crudest representation of system performance and costs.

Recommendations

- **Targeting TNUoS charges and credits in periods and locations where generator output contributes to, or relieves congestion would be an improvement to the existing**

ICRP methodology. However, this implies a time of use and congestion location feature in TNUoS charges rather than it being linked to generator annual load factors.

- **A TNUoS methodology that related charges to times and boundaries where congestion was most severe would be a significant improvement to the existing methodology. This could be achieved by introducing a time of use element (congestion factor) to the existing peak security based TNUoS charges. The present year-round scenario would be expanded to become a number of scenarios that are directly linked to congestion times and boundaries.**
- **If multiple scenarios with their respective time periods and duration are too complicated, then the existing ICRP methodology should be retained on grounds of simplicity rather than diluting and distorting its pricing incentives. Creating a dual background would be a retrograde step in the reflection of costs, and the provision of useful economic signals for transmission and generation investment.**